PEAK
NORTH DAKOTA, LLC

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February 15, 2010

Karlene Fine, Executive Director
North Dakota Industrial Commission
State Capital – 14th Floor
600 East Boulevard Ave, Dept 405
Bismarck, ND 58505-0840

Subject: Peak North Dakota grant application to simultaneously fracture stimulate two 320 acre spaced horizontal Bakken wellbores located ~1400' apart.

Ms. Fine,

Enclosed, please find Peak North Dakota's grant application requesting the North Dakota Industrial Commission to approve funding from the Oil and Gas Research Council to help fund the Simul-Frac of two, 320 acre spaced Middle Bakken horizontal wells. This application outlines the project's objective of significantly increasing production and the economic recovery of Original Oil in Place using a stimulation technique previously tested by Peak on the Fort Berthold Indian Reservation with very encouraging initial results.

The total cost of this project is expected to be approximately $10,400,000 with a request for grant funding in the amount of $750,000. In exchange for accepting grant funding in this project, Peak will make available all the relevant data from Peak's previous two years of drilling and completing wells on the reservation for use as a comprehensive data set to compare results and make informed conclusions regarding the true effectiveness of this technique.

A $100 dollar check is enclosed with the two paper copies of this letter and application that will be mailed in conjunction with this email version sent today.

If there are any additional questions regarding this project, please feel free to contact me at any time.

Thank you for your consideration,
Sincerely,

Steven M Thibodeaux
Vice President, Geologist
Peak North Dakota, LLC
1910 Main Avenue
Durango, CO 81301
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Email: sthibodeaux@colopeaks.com

Oil and Gas Research Program

North Dakota

Industrial Commission

Application

Project Title: Simul-Frac two Bakken Wells Spaced 1320' Apart to Maximize OOIP Recoveries

Applicant: Peak North Dakota, LLC

Principal Investigators: Steve Thibodeaux, Alex McLean, Vic Rudolph

Date of Application: February 15, 2010

Amount of Request: $750,000

Total Amount of Proposed Project:

$11,450,618

Duration of Project: 9 months

Point of Contact (POC): Steve Thibodeaux

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ABSTRACT

Peak North Dakota, LLC (Peak) proposes to drill and then simultaneously fracture stimulate (simul-frac) two short lateral (4000' – 4200') horizontal Middle Bakken wells located approximately 1320' apart in a 320 acre spaced drilling unit on the Fort Berthold Indian Reservation (FBIR) in order to validate a completion technique to economically maximize the recovery of Original Oil In Place (OOIP). In 2008, Peak individually completed seven short lateral (3800' – 4500') FBIR Middle Bakken wells using variously modified frac techniques, including two wells 2600' apart on standard 320 acre spacing that displayed no appreciable interference between them. In 2009, Peak drilled and then simultaneously fracture stimulated two short lateral FBIR Middle Bakken wells while using a new stimulation design in separate 320 acre drilling units but located only 1320' apart (effectively simulating 160 ac spacing). This technique also showed no appreciable interference and resulted in significantly improved production profiles (rate and pressure decline curves) when compared to the other wells in this area along with an estimated ~30% increase in projected EUR per well. Peak intends to compare the results of the proposed 2010 simul-frac wells with the two 2009 simul-frac'd wells, the original seven wells which used different stimulation designs and any well data from other willing operators on the FBIR who currently have data sharing agreements with Peak to determine which combination of factors leads to the best economics and highest recoveries of OOIP from this reservoir.

Objectives: The initial objective of this program is to test the repeatability of Peak's earlier simul-frac results on the FBIR using the same technique and revised stimulation design that resulted in significantly higher rates, better pressure decline curves and up to a 30% increase in expected EUR per well.

This project also proposes to provide all the pertinent drilling and completion data from Peak's seven well 2008 Bakken program, the 2008 two well simul-frac program and possibly additional data from willing FBIR operators in order to have the most comprehensive data set possible in this particular geologic setting from which to compare results and draw informed conclusions.

The primary objective of this program is to educate and encourage the use of new technologies by all FBIR operators and others in similar geologic settings within the Bakken petroleum system. The successful completion of this program and subsequent data evaluation by other operators will effectively help to prevent waste, provide critical data for proper planning of both present and future development and have a positive economic impact by proving up an economically attractive methodology for maximizing reserve recoveries from this resource.

Expected Results: Peak expects this project to prove up a viable drilling, well spacing and completion method which will produce the maximum amount of recoverable oil from this resource while maintaining attractive per well economics. Peak believes this method will significantly improve on the current industry reported recovery factor estimates which now range from approximately 6% to 14% in this area regardless of lateral length or stimulation design used.

This project will also provide critical data relating to well placement, lateral orientation and the timing of drilling and completion operations so that the initial development (used primarily to delineate the play and hold leases by production) can be planned and implemented in a manner that also allows the necessary future infill development to occur. Should the project be successful, it will ultimately maximize the recovery of reserves and have a positive economic and environmental impact on this and similar geologic settings within the Bakken petroleum system.

In addition, the project will provide a valuable, multi-well data base to the NDIC and therefore made available to the public for other operators to use in making their own assessments for designing improved frac techniques and the commercial viability of simul-frac'ing in this geological setting. This data can immediately be used by the NDIC when estimating what a full development scenario may look like on the FBIR where individual allottee leases are never larger than 320 acres while planning for the development and ultimate spacing requirements needed to fully exploit the economic potential of the Bakken here and in similar areas.

Duration: The project in this application consists of drilling two parallel laterals (1320' apart) from one pad (to minimize the environmental impact) then setting up a completion crew to simultaneously frac both laterals and begin production. Recently published data from the Tudor Pickering Holt Bakken report (1/21/2010) suggests that there is a strong correlation between EUR and peak monthly rates, rather than IP's or 24 hour rates, which improves further with 3 months of cumulative production. The final evaluation of these results will therefore occur after 3 months of production making the **total duration of this project approximately 9 months** (drill, complete, set facilities, initial 3 months production and comparison to earlier wells in the area).

Total Project Cost: Total project costs for the drilling, completion and comparative assessment of results from the two planned simul-frac wells is expected to be approximately $11,450,618. A budget estimate for one of the wells is included under Appendix B.

Participants: Peak North Dakota is expected to be the sole operator and financial participant in this project although data contributions of previously drilled and producing wells are possible from other FBIR operators that Peak currently has data sharing agreements with.

PROJECT DESCRIPTION

Introduction: The management team at Peak has had excellent experience acquiring and developing unconventional or tight reservoir projects prior to entering into the Bakken play including a tight sand gas and oil play in the Granite Wash of the Texas Panhandle and the Barnett Shale play. The eventual economic success from both of these other prospects ultimately depended on making technical improvements in drilling and stimulation designs along with determining proper spacing between wells order to maximize recoveries without undue interference to avoid unnecessary waste by drilling laterals either too closely together or conversely, too far apart to effectively recover resources. Peak closely noted the evolution in development for those plays as early tests allowed operators to increase efficiency in their operations with each successive quarter of data analyzed resulting in tighter placement of individual wells with improved economics, rates and recoveries as the best completion and drilling practices became common knowledge.

After learning about simul-frac wells in closely spaced laterals in the Barnett play where results were reported to increase EUR's by as much as 150% over individually frac'd laterals, Peak saw enough similarities in the way Bakken wells were currently behaving to believe this methodology also had merit here. Peak's first test of this concept in the 2009 Zane 32-24H and Voigt 32-34H wells spaced 1400' apart resulted in a dramatic improvement in both the rate and pressure decline curves along with internal estimates that EUR was increased by as much as 30% per well when compared to Peak's previous attempts in similar laterals. The projected rates and oil recovery per foot of completed lateral also exhibited significant improvement when compared to Peaks earlier wells and those operated by others (even with similar frac designs) that Peak had access to via data sharing agreements. The results were fairly straightforward as were the conclusions Peak made from the data with the remaining questions being: 1) was it the simul-frac, new stimulation design and better field execution of the completion that was the controlling factor for these obvious increases or, 2) was it just a fluke of the local geology where these two wells were drilled even though we had other completions within 2 miles to compare them to.

Peak was aware of the earlier Marathon OGRC project (G-015-029) which determined via microseismic data that simultaneously frac'ing two wells resulted in positive interference and direct evidence a significant volume rock was indeed fractured. However, this test was done with single stage, slick water fracs over ~9000' of open laterals and not via the improved fluid and proppant design currently used by Peak with the multiple stage frac designs used by the majority of industry and proven to be more effective in recovering oil from this tight rock. In addition, the primary purpose of that test was to show that hydraulic fracturing was influenced by simul-frac'ing and not whether or not this method resulted in improved economic performance and more efficient recoveries as this project is designed to do. Peak therefore decided to design a 2010 project to provide additional data for use in answering these key questions yet as a private company with a limited capital budget to implement, we are now looking for a financial partnership with the OGRC. In exchange Peak will share the data and conclusions drawn from this project along with results from what has already been a successful 2 year multi-well drilling program in this area providing key data for NDIC and industry to use in the evaluation of this important resource.

Objectives:

- To determine if a second test simultaneously frac'ing two Middle Bakken horizontal wells spaced ~1320' apart again leads to significantly improved economics and recovery factors of OOIP thereby preventing waste and maximizing the ultimate value of this resource on the FBIR.
- To provide a second, repeatable (or not) data point for use in determining effective well spacing and the potential ability for development on 160 acre spacing on the FBIR and similar areas.

- To lay the groundwork for future development planning by the NDIC and Bakken Operators by providing key data for determining what potential well spacing may ultimately be needed to recover the maximum reserves possible while still maintaining economic viability.
- To share the results of this project and all of Peak's previously drilled Bakken wells with the NDIC along with other FBIR and Bakken operators in order to encourage the use of new technologies that will have a positive economic impact for development on the FBIR and other geologically similar areas within the Bakken petroleum system.
- To prove up a technology that will allow multiple wells to be drilled and then completed from the same pad thereby reducing traffic, surface disturbance and the overall site footprint while still allowing for maximum and economically viable development of the resource to occur.

Methodology:

Drilling: Peak will drill these wells using Unit Rig 328, a 1600 hp diesel electric rig. Peak drills its wells similar to other Operators in the Williston Basin: drill the surface hole with fresh water to ~ 2500' and set and cement 9-5/8" surface casing. Peak will then change over to oil-based drilling mud (invert) and drill vertically with mud motors to kick-off point (~ 600' TVD) above the Middle Member Bakken (MMB) target. At this point, pick up required directional equipment to drill a 10 – 12 degree DLS curve and intersect the MMB target. Once the MMB target is intersected and wellbore is past the required hardline, run and cement 7" intermediate casing. Pick up 6" bit and required directional equipment and drill horizontally within the MMB target to designed TD (typically 4000' – 4300' lateral). Upon reaching TD, Peak will run necessary reamers and run a 4-1/2" liner with a pre-designed number of swell packers and possible frac sleeves (Peak typically prefers to pump down perf guns and frac plugs – commonly referred to as "pump downs" – rather than use frac sleeves). Peak places its liner top at the kick-off point with a typical timeline from move-in of rig to rig release of 22 – 25 days.

Note: Peak will provide an example Drilling Prog and APD from one of Peak's simul-frac wells within the FBIR upon request if additional technical details are needed.

Completion: Once the drilling rig is moved off, Peak moves in a workover rig and runs a CBL to determine TOC above the Dakota formation (per NDIC requirement), then runs a 4 1/2" 11.6# or 13.5# P110 Frac string, landing same in the PBR (liner top assembly). Test frac string to 5000 psi, conduct an injection-falloff test for DFIT analysis, nipple up surface BOP Frac stack, set 60 to 100 Frac tanks and fill w/ fresh water, move in Frac company and pump pre-designed multi-stage frac job. Peak will be closely monitoring pressures in each well bore during the entire completion process looking for any observable signs of communication while stimulating the adjacent well stages. Peak does NOT intend to run any micro-seismic monitoring as this is beyond the scope of this investigation which is designed to provide quantitative data regarding production increases related to this stimulation design rather than qualitative data on the amount of rock volumes affected by the fracs. Once frac job is completed and frac crew is released, start flow back. Continue flowback / production until such point that pressures allow frac string to be pulled and tubing run. Install pumping unit and run rods and pump. Typical timeline from drilling rig release to move in of frac equipment is 45 – 60 days.

Anticipated Results:

Prove a viable drilling, well spacing and completion method for producing the maximum amount of oil while maintaining attractive per well economics and reducing the cumulative Oil & Gas footprint from multiple operations.

- Significantly improve on current industry recovery factor estimates which now range from approximately 6% to 14% of the OOIP in this area regardless of lateral length or stim type.
- Provide valuable data for what a full development scenario may look like on the FBIR where individual allottee leases are never larger than 320 acres and are commonly much smaller.
- Provide a valuable, multi-well data base to the NDIC and therefore made available to the public for other operators to use in making their own assessments for designing frac techniques and the commercial viability of simul-frac'ing in similar geological settings.
- Provide important data relating to well placement, lateral orientation, timing of drilling and stimulation so that initial development wells can be planned and implemented in a manner that also allows the necessary future infill development to occur in order to economically maximize recovery factors and ultimately increase the reserves produced from this and similar areas.

Facilities:

Production facilities are set prior to the frac so the well can be produced immediately post-frac. Equipment is typical of any Bakken completion and will specifically include two of the following (one per well) heater treater , two electronic flow gas meter (EFM), 912 Pumping Unit . Facilities will also include ten 400 BBL oil stock tanks (five for each well), two 400 BBL water tanks (one for each well). Wells will be visited daily (seven days/week) by the Peak pumper, who will check, monitor and record pressures, oil and gas rates and general well conditions.

Resources:

People/Companies

- Peak management and technical team directing all past and future Bakken development
- Sunburst Consulting for wellsite geosteering and final drilling geological report
- IPT Completion consultants , conduct performance modeling
- Frac Company - Schlumberger
- Drilling Company - Unit
- Wire Line - High Plains Inc.

Finance

- Peak Energy Resources, LLC (parent company to Peak North Dakota, LLC)

- OGRC Grant

Techniques to Be Used, Their Availability and Capability:

In the summer of 2009, in an effort to increase well performance, Peak utilized the services of Integrated Petroleum Technologies (IPT), an industry-leading independent petroleum engineering services team specializing in the integration of modern well completion, hydraulic fracture stimulation and reservoir engineering technologies. Peak had IPT model reservoir performance of its existing wells. Based on this evaluation, IPT made certain recommendations to modify both proppant selection and frac fluid rheology. Peak implemented these recommendations on the completion of the Zane-Voigt wells. Further information on IPT can be found at http://www.iptengineers.com/.

Following is a summary of Peak's prior simul-fracs discussing background, frac design changes and results:

Summary:

- After modifying its frac design, the two Peak Zane-Voigt Middle Member Bakken wells yielded much stronger production results (both rate and flowing pressures) than its prior wells.

Background:

- As of September, 2009, Peak had completed 8 short lateral wells (3700' – 4300'), with oldest well being completed in May 2008. All wells were completed with 800,000 – 1,200,000 lbs proppant with cross linked gel, using 6-10 stages. Wells used a mixture of white sand and lower density/strength ISPs (Econoprop).
- After looking at an offset operator's wells that utilized IPT's frac techniques, it was apparent that well performance could be improved.
- Additionally, actual production showed a change (drop) in productivity at a point in the well life where crushing of the white sand and lower strength ceramics would be expected. Reservoir modeling further confirmed the proppant crushing. The offset operator's wells that used 100% ISP did not experience a productivity decline.

Changes:

- Changed to 100% 18/40 Versa Prop from 20/40 Econoprop (VersaProp has higher crushing resistance).
- Used a 40 lb cross lined Borate fluid system with a minimum break time of 60 minutes (previous systems used 24-28 lb borates).
- Increased pad volumes to create accommodation space to help improve proppant placement.
- Rigorous on-site monitoring of job placement was conducted.
- Total proppant volume, ramping, and pump rates were similar to the other wells Peak has completed.

Results:

- Peak recently completed two Middle Member Bakken wells on the same pad, both with 4300' laterals, 1400' separation, north-south orientation, swell packers, 7 stages/well, using 1,100,00 lbs of 18/40 Versa Prop per well.
- Based upon early results, the wells are the best performing wells Peak has completed, with the highest oil production and tubing pressures (see attached plots, Appendix A).
- After four months production, these two wells are still the two best performing short laterals on FBIR.

Environmental and Economic Impacts while Project is Underway:
The expected environmental and economic impacts during project operations will be consistent with the normal drilling and completion activities currently underway in this area. Peak undertakes both a cultural and environmental survey before obtaining right of ways and surface permission to build roads and well pads and goes through the normal BLM / BIA / NDIC permittingand approval processes before beginning construction. One immediate benefit is with a slightly larger pad, this project eliminates road and other impacts from multiple rig moves along with containing the frac crew and equipment to a single site reducing the overall footprint and road traffic of drilling and completion activities.

Ultimate Technological and Economic Impacts:

The geological setting in this particular area of the FBIR suggests that there is excellent sourcing and oil saturation of the primary target (Middle Bakken member) yet this area has lower porosities and permeabilities than seen in the more prolific regions such as the Parshall and Sanish fields due north of here. Should this project again produce similar results to Peak's earlier 2009 simul-frac wells that had a 30% increase in EUR per well, then the implications for improved economics along with recovering 30% additional reserves in a more efficient and environmentally sound manner are profound. The impact of this technology is likely to extend well beyond the boundaries of the several hundred thousand acre FBIR region as many similar tight geological regions in the Bakken may also benefit and become more economically attractive to industry development.

Why the Project is Needed:

The OGRC Marathon project (G-015-029) used micro seismic measuring to determine if a simul-frac produced minute earth cracking phenomenon that were influenced by each other during the process using a less efficient single stage frac design. Peak's proposal tests the simul-frac method using a more commonly accepted multi-stage frac, proven by industry to more efficiently recover reserves, along with an improved stimulation design and will directly compare economics, production decline profiles and recoveries between wells with various stimulation designs, lateral orientations and lengths to determine the most effective and economically viable completion method.

Current spacing and completions on the FBIR (and elsewhere) are poorly coordinated between different operators making for difficult planning at the NDIC when drilling spacing units anywhere from 320 acres to 2560 acres are proposed with single to multiple wells, lengths and orientations planned. If the ultimate goal of the NDIC is to prevent waste and the unnecessary drilling of wells while promoting the maximum recovery of hydrocarbons possible, then this will be a key data set to aid in the overall development planning process. Of particular concern on the FBIR is the maximum single lease size of 320 acres with many being considerably smaller and ownership is fractionated between numerous oil companies necessitating forced pooling and other issues to ensure development. It is vital to understand the most practical way to develop reserves and efficiently recover oil from this tight reservoir in order to make informed decisions for both current and future development.

Additionally, as historic evidence shows, tight unconventional reservoirs undergo a fairly predictable evolution in development starting with the initial well or technology that unlocks economic reserves. Once the economics and potential are discovered and leasing has occurred over the expected boundaries of the play, numerous operators begin drilling wells and experimenting with different drilling and completion methods in order to improve single well economics while trying to hold all the leases acquired in the economically viable areas by existing production. After the initial round of primary drilling there comes a second round of infill drilling where operators try and determine the maximum density of wells needed to effectively recover hydrocarbons without causing undue interference between wells and wasteful, unnecessary drilling. Once infill drilling has occurred to the maximum extent possible the final stages of development usually involve secondary production enhancement by various methods such as re-fracs or water and CO_2 flooding of existing wellbores. By undertaking this project early in the life cycle of this particular Bakken resource and understanding potential interference and spacing issues, proper planning of the initial wells drilled can occur in such a manner as to allow room for the inevitable second wave of infill wells to be drilled for proper drainage to occur. This allows for better planning of well pad and lateral placement, road and infrastructure needs, environmental impacts and industry services required in order to reach this second stage.

Finally, current industry reported recovery factors range from approximately 6% (or less) to just over 14% of the OOIP from this valuable resource. This is regardless of the type of stimulation used and orientation or length of the lateral by multiple operators. Should this project confirm an economically sound methodology for increasing well EUR's by as much as 30% (as the original 2009 Peak simul-frac did) then the economic impacts for the much larger Bakken play as a whole are very significant.

STANDARDS OF SUCCESS

Measurable Deliverables:

- Peak will successfully complete the drilling then set casing and packers readying both lateral wellbores for completion. Peak assumes 100% of the financial responsibility and mechanical risk for this portion of the work and if it cannot have both wellbores ready for a multistage simul-frac operation as planned, then the request for a grant is negated.
- Peak will successfully complete the simul-frac stimulation in both wells. The requested Grant amount of $750K from the OGRC represents less than 50% of this anticipated completion cost.
- Peak will submit all 90 day production information (water, oil, gas, flowing pressures, etc) along with the additional information needed (lateral length, orientation, type of frac, number of

stages, etc) to compare these results with those of all other FBIR Peak operated Bakken wells with the possibility of including additional like data from Peak data sharing partnerships.

- EUR's and estimated recovery factors for all wells in the study will be calculated by Peak and can be further validated by either a 3rd party engineering firm or by the Commission's technical reviewers.
- Economic evaluations are somewhat subjective and can be run by different companies and public entities in a variety of methods. Peak will therefore quantify this project a success if the production from these simul-frac wells shows either a 20% to 30% increase in EUR or 20% to 30% increase in oil recovered per foot of lateral stimulated over the comparable, individually completed wells included in this study. This would have profound implications for additional recoverable reserves over large portions of the basin where similar geological settings are found.
- While the primary means of measuring success here will be actual production comparisons between this project and other wells in this similar geological setting, there will be additional analyses done and made available as part of this study. Peak has used IPT (Integrated Petroleum Technologies) to conduct production modeling on a number of existing wells to determine estimated reservoir properties and effective fracture geometries. Before the wells are stimulated, injection fall-off test will be conducted on the first stage perforations and a DFIT analysis conducted to determine reservoir permeability and pressure. IPT will use the DFIT data to make preliminary performance predictions on the planned completion of the Simul-Frac wells. This will be compared to the actual production performance from the wells to determine any benefit from the Simul-Frac technique. An effort will be made to determine the new effective fracture geometry created by the Simul-Frac on this project and those results compared to the existing two Simul-Frac wells to validate the predictions

Value and Use:

- Direct value to North Dakota will be realized as increased production tax revenue and an increase in state lease sales prices should this methodology prove capable of increasing reserves in tighter portions of the reservoirs by as much as 30%.
- Additional value will be seen if this technology is tried and proven in portions of the basin currently deemed too tight to achieve desirable economics, thereby opening significantly more of this resource to additional development.
- More development in tighter areas of the reservoir directly translates to more job creation as additional operators are attracted to an expanded area of economic development.
- Definitive data suggesting that effectively spacing laterals on 160 acres (1320' between laterals) recovers significant incremental (not accelerated) reserves directly leads to the prevention of waste and allows the state, mineral owners and operators to economically benefit from incremental reserves produced and to better plan for both initial development and subsequent infill development scenarios. *Note: for clarification, effective 160 acre spacing is equivalent to two short laterals on 320's, 4 on 640's and 4 long laterals on 1280's spaced approximately 1320'

apart. As such, this type of completion can be effectively used on ANY laterals spaced ~1320' apart regardless of their length or the drilling and spacing unit they may be drilled in.

- Proving that multiple laterals can be effectively simultaneously frac'd from the same well pad reduces the overall Oil and Gas footprint required for full development scenarios by reducing traffic use and reducing surface disturbance by building fewer well pads or access roads and therefore has a direct environmental benefit.
- Reporting on the progress and success of this project along with the methods used to measure success are outlined in detail under the Management portion of this form.

BACKGROUND/QUALIFICIATIONS

Peak North Dakota has successfully drilled and completed nine Middle Bakken short laterals, two of which were simul-frac'd, two Three Forks short laterals and one 10,000' Middle Bakken lateral (currently waiting on completion as of Feb 15, 2010) in the past 2+ years. Along with Peak's considerable in-house expertise (details of which are listed in our website at: http://www.peakenergyresources.com) Peak has retained the capable drilling supervisors, mudlogging/geological consultants, directional consultants, completion consultants and frac companies used in our previous development programs here. Outside the Bakken play (details also on the website) the Peak technical team has drilled and completed fifty five wells in the deep Granite Wash of the Texas Panhandle, eight horizontal wells and one water disposal well in the Barnett Shale play, sixteen shallower oil wells in Nebraska and sixteen medium to deep gas wells in the Wind River Basin over the past +6 years. The three principal investigators (Steve Thibodeaux-VP, Geologist; Alex McLean-President, Engineer and Vic Rudolph-VP, Production Engineer) have designed and overseen operations in all of these projects for Peak and respectively have 29, 28 and 25 years of direct experience in the business. In addition, Peak's VP of drilling, Everett Toombs, has 46 years of drilling experience and Peak's CEO and Chairman, Jack Vaughn, has 42 years of experience as a Petroleum Engineer.

MANAGEMENT

Management of the Drilling Program:

- The Commission will be provided an information package containing the pertinent plats, permits, APD's, drilling / geological prognosis' and directional plans for both wells prior to spud.
- The Commission will be provided the final daily drilling reports, geological reports and mudlogs, actual lateral profile drilled with directional surveys, casing reports and well bore diagrams for each planned lateral after completion of this portion of the program.

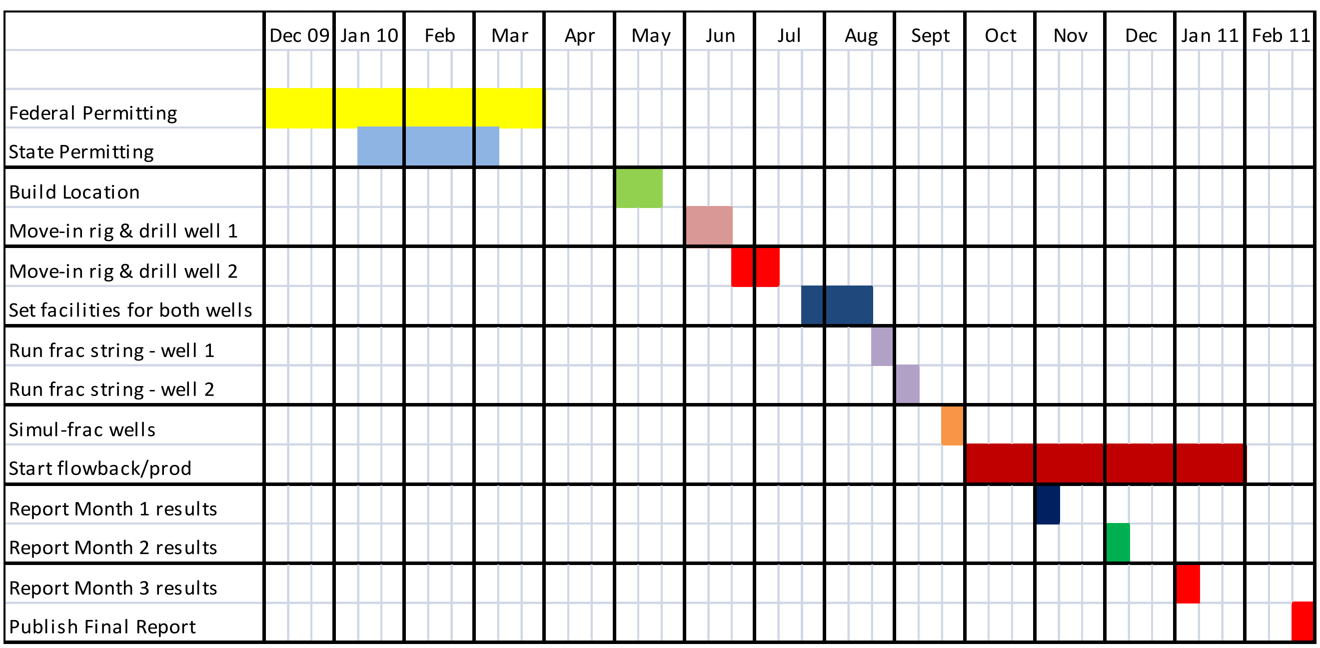
Management of the Completion Program:

- The Commission will be provided a comprehensive completion plan prior to commencing operations.
- The Commission will be provided a detailed daily completion (frac) report for the simul-frac job shortly after these procedures are finished in the field and the report is finalized. See appendix C for a sample of the type of detailed frac reporting that will be provided for the research simul-frac wells. This data contains significantly more detail than the generic, form 6 reports currently provided to the NDIC.
- The Commission will be provided a complete facilities report once the equipment has been set and flow back commences.
- The Commission will be provided production reports (spreadsheets and charts listing gas, oil, water and flowing pressure data both in daily and cumulative formats) at 30, 60 and 90 day intervals following the commencement of first production. These production reports will also have the same information in charts and spreadsheets for the comparative wells used in this study so that a direct, visual comparison can be made as the wells begin to produce.

Management of the Evaluative Program:

- Peak will submit a final report after 90 days of production from the simul-frac wells comparing all pertinent production data and projected EUR's (which can then be independently projected by either a 3rd party engineering firm or by the Commission's independent reviewers) and submit conclusions regarding the effectiveness of this technique versus others in this study.

TIMETABLE



BUDGET

Project Associated Expense	NDIC's Share	Applicant's Share (Cash)	Applicant's Share (In-Kind)	Other Project Sponsor's Share
Drilling	$0	$5,270,948		n/a
Completion	$750,000	$5,353,470		n/a
Facility	$0	$826,200		n/a
Total	$750,000	$11,450,618		n/a

The total budget of $11,450,618 covers the cost to drill and complete the two wells along with the data analysis reporting. If less funding is available from the OGRC than requested, Peak will assess the value of any grant monies given versus the time and expense of preparing this data for public reporting and use by other operators. Should that value be enough to continue, no delays would be expected. If that value was estimated as insufficient to warrant the extra time and expense incurred by Peak to share this data publicly, then, Peak will rescind its request for grant monies, continue with this project and keep all results and well data confidential. Peak Energy Resources, LLC intends to be the sole provider of matching funds on this project which is expected to be 100% operated by Peak with no anticipated partners. The only other source of potential funding being considered is from this grant request. Indirect costs such as employee salaries and other related items will also be entirely covered by Peak.

CONFIDENTIAL INFORMATION

Peak intends to waive the tight hole status of this well and provide / include all of the production data and pertinent well information needed for the evaluation of the project. This will also include like kind data from Peak's previous simul-frac and individually frac'd wells, which is what makes this entire data set so valuable for the NDIC and public as this previous work constitutes over $60MM worth of data acquired to date.

PATENTS/RIGHTS TO TECHNICAL DATA

Peak does not currently hold or expect to hold patent rights to any of the techniques or methodologies used in this project.

STATUS OF ONGOING PROJECTS (IF ANY)

Peak has not been the recipient of any previous funding from the Commission.

AFFIDAVIT OF TAX LIABILITY

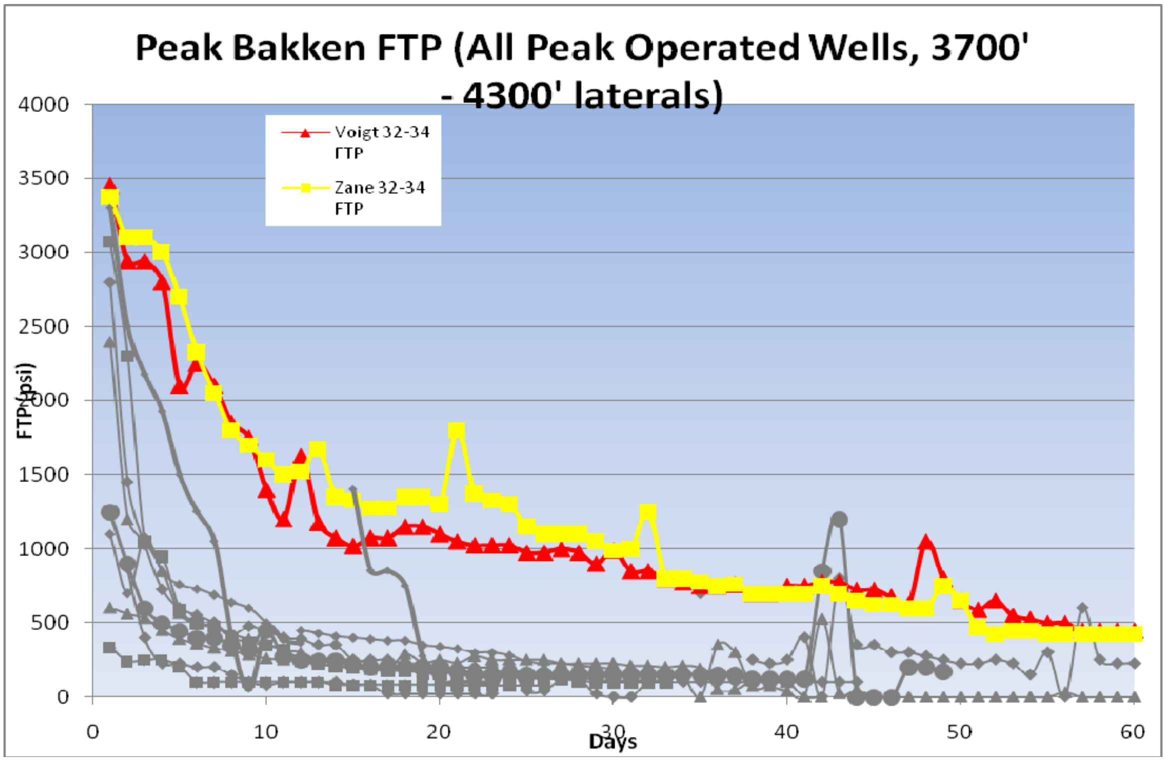
I, Alex McLean, certify that Peak North Dakota, LLC does not have any outstanding tax liability owed to the State of North Dakota or any of its political subdivisions.

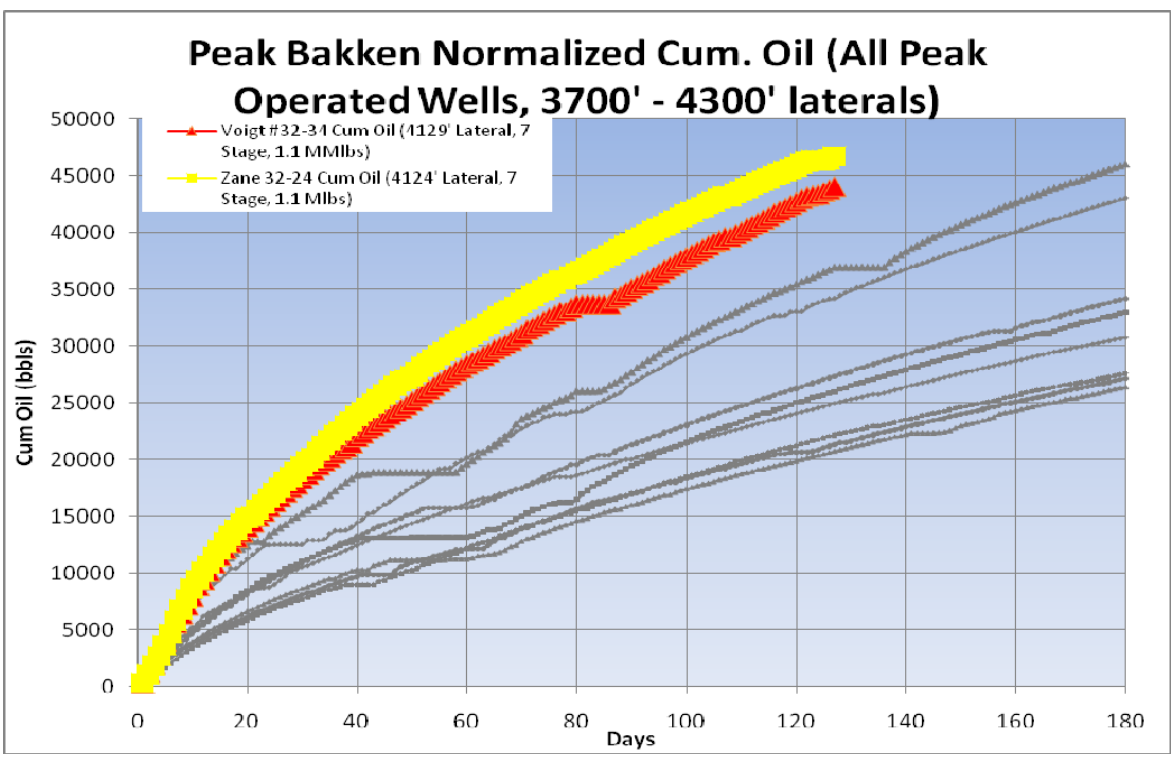
____ ____________________

Alex McLean, PE President Date

Appendix A

Comparative Production Charts for Zane and Voigt 2009 Simul-Fracs





Appendix B

Budget Estimate to Drill and Complete One of the Two Simul-Frac Wells

FIELD / PROSPECT : Bakken	WELL NAME: Simul-Frac Well #1			AFE NO.	
PROPOSED TD: 16,000	COUNTY: Dunn	STATE: ND			
PROJECT DESCRIPTION: Drill a 160 Acre Spaced Well and Simul-Frac				PEAK NO.	
LEGAL LOCATION:					
AFE TYPE: XX DRILL & COMPLETE	CAPITAL - REC	EXPENSE W/O		DATE	3/1/10

INTANGIBLE EXPENSES Description	Comments	DRY HOLE CODE 230/ $	SUB-CODES	COMP w/DRLG RIG CODE 240/ $		COMPLETION CODE 240/ $		GRAND TOTAL $
Anchors			115			1,600		1,600
Archeological Services		2,100	120					2,100
Bits, Reamers, and Stabilizers		65,000	140					65,000
Casing Crews & Services		48,000	160	18,000				66,000
Cement & Cement Services		64,650	170					64,650
Chemicals - Corrosion & Scale			180			20,000		20,000
Coiled Tubing Unit			190			75,000		75,000
Communications		4,500	195	1,500				6,000
Consulting - Engineer	Fracture Modelling and Production Modelling		236			15,000		15,000
Contingencies	10%	196,576	245			195,560		392,136
Contract Labor		7,500	250			10,000		17,500
Directional Drilling		180,000	270					180,000
Dirt work, Road, Location & Pits		120,000	275			10,000		130,000
Drilling Day Work	22 days @ $ 15,500 per day	341,000	294	77,500				418,500
Fracturing	10 stages, 1.2 MM lbs ISP		355			1,100,000		1,100,000
Fuel (Diesel, Propane, Nat Gas)	2800 Gal/Day @ $2.10/Gal	115,500	375	29,400				144,900
Hot Oiler			405			50,000		50,000
Insurance & Bonds		18,000	410					18,000
Legal Fees		510	420					510
Logging, Cased Hole			430			12,000		12,000
Logging, Open Hole			435					0
Miscellaneous		5,000	460					5,000
Mud & Chemicals		150,000	465					150,000
Mud Logging	15 Days at 1500/Day	22,500	475					22,500
Overhead		6,500	535					6,500
Perforating	10 pump downs @ 13,500 each		555			135,000		135,000
Permitting		119,300	560					119,300
Pumping Services			610			15,000		15,000
Quarters & Catering		35,000	630	2,925				37,925
Rathole/Mousehole/Conductor		21,000	635					21,000
Reclamation Services		50,000	640					50,000
Rental Equipment - Downhole	9 Frac plugs @3000 each +5000		655			32,000		32,000
Rental Equipment - Frac Tanks			660	25,000		125,000		150,000
Rental Equipment - Surface		68,200	665	14,000		22,000		104,200
Rig - Workover/Completion			680			63,000		63,000
Rig Mob/Demob	(includes 3 days standby time at $30K/day)	275,000	685					275,000
Supervision - Rig Work	22 Days @ $1500/Day	33,000	730	7,500		20,000		60,500
Supplies & Materials		5,000	735					5,000
Surface Damages		10,000	740					10,000
Surveying & Signs		5,000	745					5,000
Title Opinion		8,000	760					8,000
Trucking		40,000	765			15,000		55,000
Tubular Inspection & Testing		10,000	780					10,000
Water Disposal (including trucking		35,000	805			50,000		85,000
Water Purchase and Trucking		30,000	820			120,000		150,000
Welding		5,000	830					5,000
Well Testing			835			65,000		65,000
TOTAL INTANGIBLE EXPENSES		2,096,836		175,825		2,151,160		4,423,821

Appendix B

Budget Estimate to Drill and Complete One of the Two Simul-Frac Wells

FIELD / PROSPECT : Bakken	**WELL NAME: Simul-Frac Well #1**		**AFE NO.**
PROPOSED TD: 16,000	**COUNTY:** Dunn	**STATE:** ND	
PROJECT DESCRIPTION: Drill a 160 Acre Spaced Well and Simul-Frac			**PEAK NO.**
LEGAL LOCATION:			
AFE TYPE: XX **DRILL & COMPLETE**	**CAPITAL - REC**	**EXPENSE W/O**	**DATE** 3/1/10

TANGIBLE EXPENSES		SUB-CODES	DRY HOLE CODE 250/ $	COMPLETION CODE 240/ $	GRAND TOTAL $
Casing - Drilling Liner	' of @ $ per ft	150			0
Casing - Intermediate	11000 ' of 7" @ $ 33.75 per ft	152	371,250		371,250
Casing - Production	' of 45 per ft	154			0
Casing - Surface	2500 ' of 9-5/8" @ $ 45.00 per ft	156	112,500		112,500
Casing Accessories	DV Tool, ECP, Float Equip, Frac Sleeves	158			0
Casing - Production Liner	5500 ' of 4.5" @ $ 13.50 per ft	162		74,250	74,250
Cathodic Protection		165			0
Conductor Pipe	' of @ $ per ft	220			0
Contingencies		245	49,888		49,888
Gas Lift Equipment		390			0
Liner Hanger		425		45,000	45,000
Miscellaneous		460			0
Packers/Tbg Anchors	(9 Swell Packers at 7500 +5000)	545		72,500	72,500
Pumps, Rod Pumps		626		7,000	7,000
Sucker Rods		720		70,000	70,000
Tubing	11000 ' of 2-7/8" @ $ 6 per ft	770		66,000	66,000
Tubing Access (nipples, etc.)		775		2,500	2,500
Wellhead Equipment		840	5,000	12,500	17,500
TOTAL TANGIBLE EXPENSES			538,638	349,750	888,388

FACILITY/PIPELINE EXPENSES	CODES	TOTAL $
Buildings	270/145	13,500
Contract Labor	270/250	50,000
Crane Service	270/260	10,000
FACILITY/PIPELINE EXPENSES (CONT)	CODES	TOTAL $
Engines	270/315	37,500
Meter Run	270/450	7,500
Pipe (line pipe)	270/565	12,000
Pumping Unit	270/615	135,000
Pumping Unit Base	270/616	8,100
Pumps (centrif, Triplex, etc.)	270/620	2,500
Separator	270/695	45,000
Tanks, Ladders & Walkways (Tank Battery)	270/755	50,000
Trucking	270/765	7,000
Valves & Fittings	270/785	35,000
Welding	270/830	0
TOTAL FACILITY/PIPELINE EXPENSES		413,100

AFE SUMMARY	Grand Total $
DRY HOLE	**2,635,474**
COMPLETION	**2,676,735**
FACILITY/PIPELINE	**413,100**
P&A	**0**
TOTAL AFE COST ESTIMATE	**5,725,309**

Appendix C

Completion (Frac) data comparisons between what is reported to NDIC and what will be provided by Peak if this Grant request is successful.

Once a Bakken well is completed, each Operator is required to submit a Form 6 Completion Report (example copy attached). The report does not require much, if any, details on the frac itself. The report does not require that the Operator disclose the number of stages, fluid type, treating rates or pressures, frac gradient, proppant type or size or any other data which may be useful for the NDIC or other Operators in determining why well performance exhibits certain characteristics. The only data required is under "PERFORATION & LATERAL RECORD".

If Peak gets this grant, it will include in its follow-up report, a full stage-by-stage report by its fracture stimulation consulting company, IPT, that defines every element of the frac, including fluid type and properties, sand type, second-by-second treating parameters (including rate and pressure), graphic analysis, the pre-frac DFIT (pump-in) test and results and a myriad of other info which will be beneficial to the NDIC, other Operators and Service Companies in defining and understanding better stimulation techniques for the Bakken / Three Forks resource. An example of this 48 page report for *a single stage* of one Peak well is attached. Note that this report is only for Stage 1 of a 7 stage frac. Additional reports will be submitted for specific each stage.

WELL COMPLETION OR RECOMPLETION REPORT - FORM 6

INDUSTRIAL COMMISSION OF NORTH DAKOTA
OIL AND GAS DIVISION
600 EAST BOULEVARD DEPT 405
BISMARCK, ND 58505-0840
SFN 2468 (02-2004)

RECEIVED OCT 2009 ND OIL & GAS DIVISION

Well File No. **17725**

PLEASE READ INSTRUCTIONS BEFORE FILLING OUT FORM.
PLEASE SUBMIT THE ORIGINAL AND ONE COPY.

Designate Type of Completion
☑ Oil Well ☐ EOR Well ☐ Recompletion ☐ Deepened Well ☐ Added Horizontal Leg ☐ Extended Horizontal Leg
☐ Gas Well ☐ SWD Well ☐ Water Supply Well ☐ Other:

Well Name and Number: **Voigt 32-34H**	Spacing Unit Description: **320 acres** E/2 Sec 32-148-93
Operator: **Peak North Dakota, LLC** — Telephone Number: **(970) 375-3133**	Field: **McGregory Buttes**
Address: **1910 Main Avenue**	Pool: **Bakken**
City: **Durango** — State: **CO** — Zip Code: **81301**	Permit Type: ☑ Wildcat ☐ Development ☐ Extension

LOCATION OF WELL

At Surface		Qtr-Qtr	Section	Township	Range	County
250 F S L	2340 F W L	SESW	32	148 N	93 W	Dunn

Spud Date	Date TD Reached	Drilling Contractor and Rig Number	KB Elevation (Ft)	Number of DSTs Run (See Back)
July 9, 2009	July 31, 2009	H & P 258	2185	0

Type of Electric and Other Logs Run (See Instructions)	Was Well Cored? ☑ No ☐ Yes / List Intervals:	Directional Survey Run? ☐ No ☑ Yes
OH waiver obtained		

CASING RECORD (Report all strings set in well)

Casing Size (Inches)	Measured Depth Set (Feet)	Hole Size (Inches)	Weight (Lbs/Ft)	Sacks Cement	Top of Cement
9-5/8	2537	12-1/4	36	820	surface
7"	10906	8-3/4	29 & 32	785	2992

LINER RECORD / TUBING RECORD

Liner Size (Inches)	Hole Size (Inches)	Top (MD) (Feet)	Bottom (MD) (Feet)	Sacks Cement	Size (Inches)	Depth Set (MD,Ft)	Anchor Set (MD,Ft)	Packer Set (MD,Ft)
4-1/2	6	9959	14502	n/a	4.5"	9959		9959

PERFORATION & LATERAL RECORD

Well Bore	OH or Perforated Interval (MD,Ft)	Kick-off Point (MD,Ft)	Top of Casing Window (MD,Ft)	Total Depth (MD,Ft)	Acid, Frac, Sqz, Etc.	Amount and Kind of Material Used
1	10906-15035	10003	-	15035	frac	22,498 bbls & 1,122,681 lbs
						18/40 versaprop

PRODUCTION

Current Producing OH or Perforated Interval(s), This Completion, Top and Bottom, (MD): **Bakken 10,906' - 15,035'**	Name of Zone (If Different from Pool Name): **Bakken**

Date of First Production Through Permanent Wellhead	Producing Method (Flowing, Gas Lift, Pumping - Size & Type of Pump)	Well Status (Producing or Shut-In)
October 10, 2009	flowing	producing

Date of Test	Hours Tested	Choke Size	Production for Test	Oil (Bbls)	Gas (MCF)	Water (Bbls)	Oil Gravity - API (Corr.)
October 12, 2009	24	20/64		992	598	1518	39 °

Flowing Tubing Pressure (PSI)	Casing Pressure (PSI)	Calculated 24-Hour Rate	Oil (Bbls)	Gas (MCF)	Water (Bbls)	Gas-Oil Ratio
2940	0		992	598	1518	603

Test Witnessed By	Oil Purchaser	Oil Transporter	Disposition of Gas
Rick Sandau	Plains Marketing, LP	Mann Enterprises	flared

On-Site Stimulation Service Report

Peak Energy Resources, LLC
Voigt #32-34 Stage 1
Bakken Formation
Wildcat Field
Dunn County, ND

October 6, 2009

Integrated Petroleum Technologies, Inc.

IPT

405 Urban Street, Suite 401
Lakewood, Colorado 80228
Phone: (303) 216-0703
Fax: (303) 216-2139

1050 East 2nd Street, #209
Edmond, Oklahoma 73034
Phone: (405) 842-2576
Fax: (303) 216-2139

Mr. Rudolph:

Attached please find information from the stimulation treatment pumped in the Bakken formation for the Voigt #32-34 (Stage 1) well. The treatment was pumped by Schlumberger on October 6, 2009.

Thank you for allowing IPT to be of service to you and Peak Energy with this stimulation. If you have any questions regarding this information, I may be contacted via my cellular phone number listed below.

Sincerely,

David G Morris
Stimulation Specialist
Integrated Petroleum Technologies, Inc.
1050 E. 2nd St. #209
Edmond, OK 73034
Cellular: (405) 808-7450
Work: (405) 842-2576
Fax: (303) 216-2139
email: DMorris@iptengineers.com
Website: www.iptengineers.com

TABLE OF CONTENTS

On-Site Fracture Stimulation Treatment Summary

Preliminary Observations:

•Testing of the Schlumberger fluid was performed in great detail weeks prior to the treatment to ensure the fluid system would work. This testing proved beneficial and the system was fine tuned in order to achieve the desired viscosity prior to entry and have the ability to break effectively as desired for sufficient cleanup.
•The liquid additive system confirmation tests were performed during the rig up day and prior to the treatment on the pumps that could not be tested. These tests indicated that the liquid additive pumps would perform as needed and no problems were observed.
•Review notes in the Operational Notes for details on the rig up day.

Diagnostic Pump-in/Shut-in Evaluation:

•Prior to the treatment, no diagnostics were performed. A DFIT was performed on this well.

Treatment Execution:

The treatment was started at 10:05 am after both wells were opened.
•The treatment design was modified to add a linear gel stage that filled the wellbore and ensured the casing was clear and that there would be no problem in achieving the desired rate. A lesser volume was asked for but due to getting chemicals lined out some extra linear was pumped.
•After pad was stage it brought to IPT attention from the samples that were brought in to the TMV that the (J920) was on traveling down on side of the Pod, this was due to the curb side was plugged off from not being used in some time.
•As the crosslinked fluid traveled down the pipe, a 700 psi pressure increase was observed and upon entry into the formation a 300 psi crack kick was observed that indicates a narrow width was present from the linear gel and the crosslinked gel was supplying a wider fracture for better proppant distribution.
•Another aspect to running the fluid with the IPT formulation is that the fluid not only maximizes lateral proppant distribution, it minimizes the packer differential pressure since the width is built prior to the entry of proppant and no excess back pressure and diversion are seen due to this on the packer.
•An adjustment was made to the delaying agent (J511) during the first crosslink pad in order to optimize the fluid and minimize the friction observed. This change from 3 to 1 gpt achieved a sufficient fluid due to the lower water temperature at the start of the treatment. Due to the tank temperatures increasing the (J511) was increased to 2.0 gpt later in the treatment.
•Viscosity was lost during the treatment due to the tank ran out of gel, it was switched and viscosity was increased by 0.4 gpt to increase viscosity.
•The treatment was performed as designed and flushed to completion. Pressure response indicates good proppant distribution was achieved with the treatment.

Inventory:

•Inventory review at the end of the treatment indicated good control of the additives was maintained which would be expected from the preliminary testing of the liquid additive pumps.

General Observations:

•Overall Schlumberger did a good job on the rig up and the implementation.

Field Ticket Review:

A review of the ticket will be performed at the end of the final stage.

On-Site Fracture Stimulation Post-Treatment Report

Company:	Peak Energy Resources, LLC	Date:	October 6, 2009
Well name:	Voigt #32-34	Stage no:	1
County:	Dunn	State:	ND
Field:	Wildcat	Formation:	Bakken
Base fluid type:	40 # Borate		
Start well pressure (psi):	3,418		

Pre-Treatment Diagnostic:

Load volume:	0	(bbl)	Total diagnostic volume:		0	(bbl)
Break pressure/rate/volume:	5,899	(psi)	10.6	(bpm)	6	(bbl)

Main Treatment:

Total clean pad volume:	41,420	(gal)	40# Borate
Total slurry volume:	140,322	(gal)	Total Slurry volume
Pumped proppant volume:	157,450	(lb)	18/40 VersaProp 157,450 lb (Weight Tickets)
Design proppant volume:	156,500	(lb)	18/40 VersaProp 156,500 lb
Proppant in wellbore:	0	(lb)	18/40 VersaProp
Proppant concentration ranges:	0.25-4.0	(ppg)	18/40 VersaProp

	Well Stg	Stage	End of Stage		Proppant Volume		Clean Volume	
			Pressure	Rate	Cum	Stage	Cum	Stage
			(psi)	(bpm)	(lb)	(lb)	(bbl)	(bbl)
Rate & Pressure – Linear	1	0	8,148	40.0	0	0	337	337
Rate & Pressure – XL Pad	1	1	8,684	39.8	0	0	942	605
Rate & Pressure – 0.25 ppg	1	2	8,549	40.0	433	433	1,003	61
Rate & Pressure – Pad	1	3	8,611	40.0	433	0	1,347	344
Rate & Pressure – 1.0 ppg	1	4	8,592	40.3	17,340	16,907	1,789	442
Rate & Pressure – 2.0 ppg	1	5	8,332	40.0	58,930	41,590	2,317	528
Rate & Pressure – 3.0 ppg	1	6	8,241	40.0	101,900	42,970	2,676	359
Rate & Pressure – 4.0 ppg	1	7	7,968	38.6	147,700	45,800	2,992	316
Avg Rate & Pressure – Flush	1	8	7,623	37.0	147,700	0	3,208	216

Well Stg	Times	Pressures	Volumes			Treating Pressure		Injection Rate	
			Treatment	Wellbore	Total Load	Average	Maximum	Average	Maximum
	(min)	(psi)	(bbl)	(bbl)	(bbl)	(psi)	(psi)	(bpm)	(bpm)
1	ISIP	4,995	3,209	225	3,434	8,321	8,904	38.3	40.8
	5 min	4,435	Previous Load		0	Pump down included on stage 2			
	10 min	4,311	Pump down Volume		0				
	15 min	4,266	Total Load to Recover		3,434				

Chemical Inventory:

#	Chemical	(Units)	Design	Actual
1	B-306	gal	1,090	1,217
2	J353	gal	60	42
3	L064	gal	118	134
4	Gyptran T106	gal	165	0
5	F103	gal	118	130
6	J920	gal	654	624

#	Chemical	(Units)	Design	Actual
7	J481	lb	68	0
8	J475	lb	27	27
9	J218	lb	28	33
10	J511	gal	436	200
11	J600	gal	9	0

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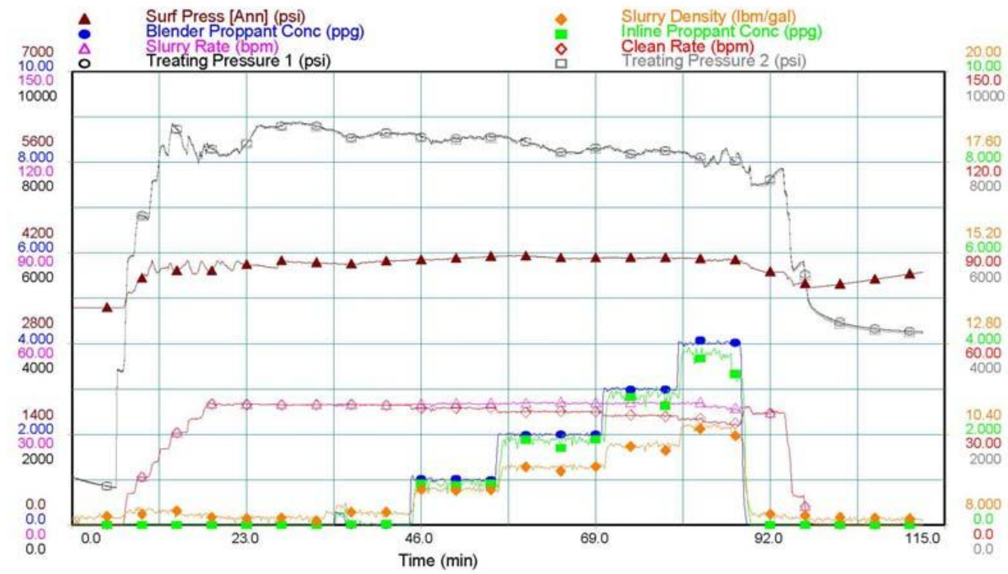
Treatment Data Plot



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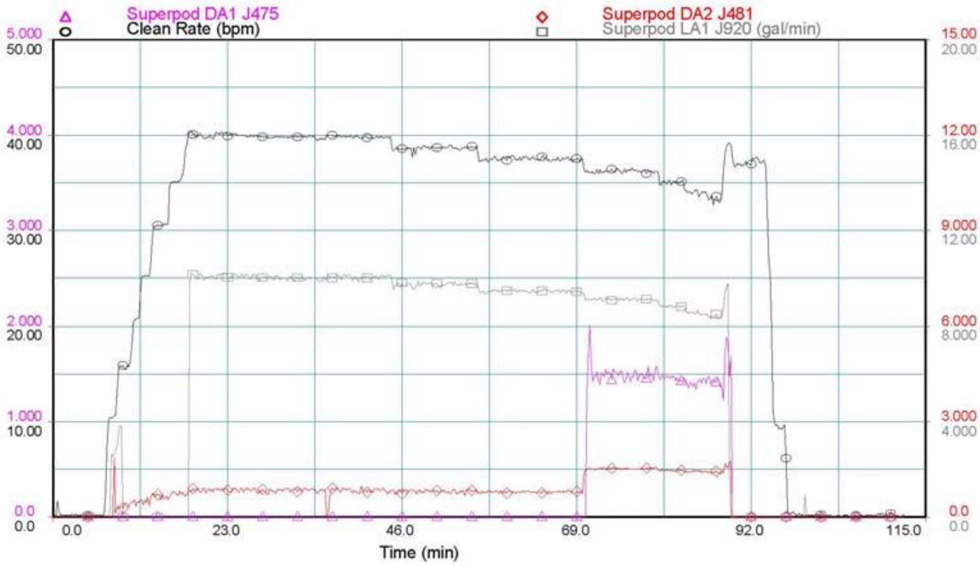
Blender Chemical Plot



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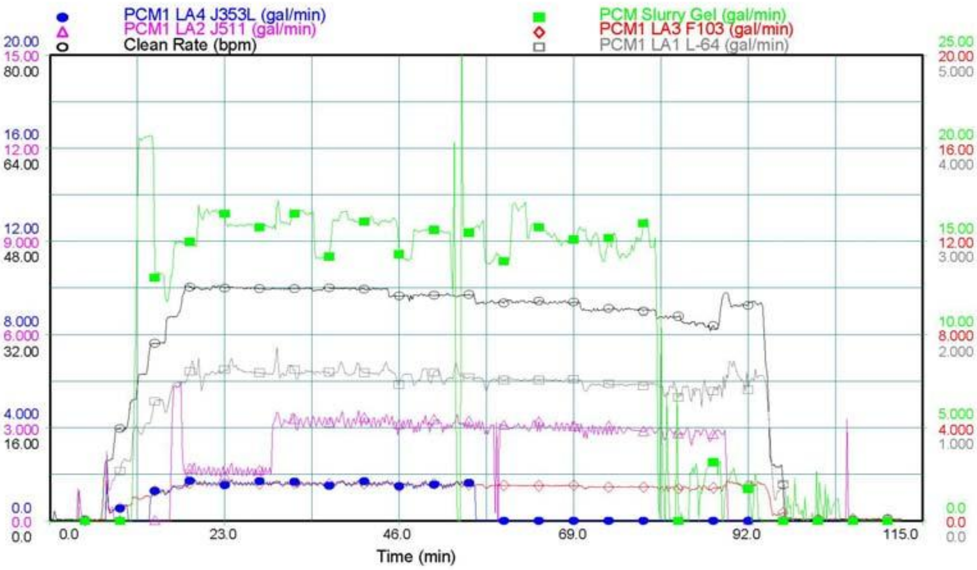
PCM Chemical Data



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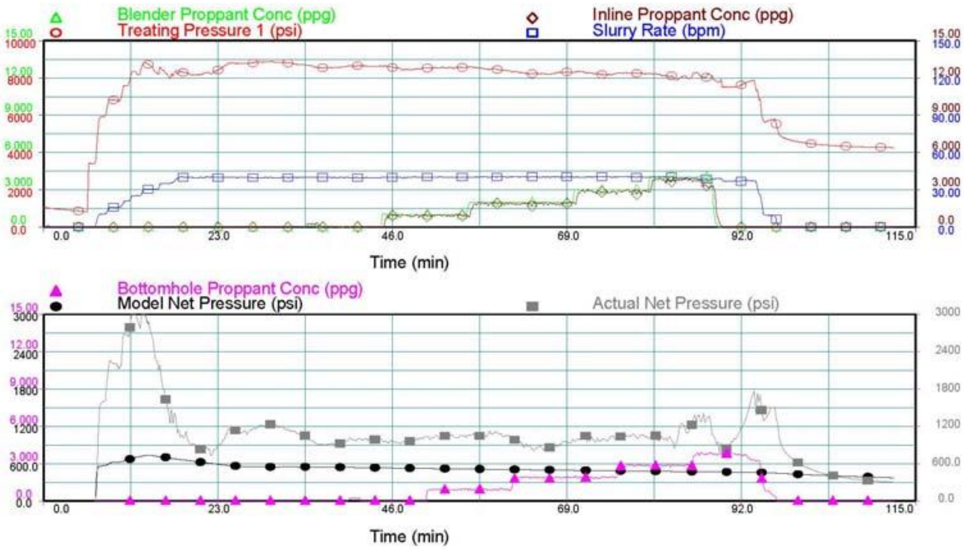
Treatment Net Pressure History Match



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Real-Time Treatment Data:

Well Stage (No.):	1			
Top perf MD and TVD (ft):	14,455	10,533	Volume to entry point (bbl):	218.5
Flush volume (bbl):	218.5		Volume to ball hit (bbl):	n/a
Start time (hh:mm AM/PM):	10:05		Volume to liner top (bbl):	n/a

FpPT Time (min)	Treating Pressure (psi)	Slurry Rate (bpm)	Inline Prop (conc)	Cum Volumes Clean (bbl)	Cum Volumes Proppant (lb)	J-511 Conc (gpt)	Temp deg	Visc cp	Remarks	Well Stg	Begin Stg
	3,418	0.0	0.00	0.0	0	0		64.0	Open Well	1	p
6.80	3,408	0 - 9	0.00	0.0	0	0		64.0	Load linear	1	l
7.50	5,899	10.6	0.00	6.0	0	0		64.0	Break	1	b
8.70	6,851	15.8	0.00	19.2	0	0		64.0	Rate and pressure	1	
13.20	8,869	30.0	0.00	112.0	0	0		64.0	Start J353L	1	
15.80	8,399	35.2	0.00	195.0	0	3.0	78.0	55.0	Start J511	1	
18.00	8,349	40.3	0.00	276.0	0	1.0	65.0	55.0	Start J920	1	
19.60	8,148	40.0	0.00	337.0	0	1.0		55.0	Main Pad J920 1 side of Pod 11.5 pH	1	1
29.20	8,887	39.9	0.00	723.0	0	2.0	78.0	51.0	Increase J511	1	
34.70	8,684	39.8	0.25	942.0	0	2.0			Start 0.25 ppg	1	2
36.30	8,549	40.0	0.00	1,003.0	433	2.0	84.0	51	Pad 11.0 pH	1	3
44.90	8,611	40.0	1.00	1,347.0	433	2.0	84.0	51	Start 1.00 ppg 11.5 pH	1	4
52.90	8,544	40.1	1.00	1,658.0	12,270	2.0	83.0	39.0	Lost gel @ PCM one side went empty up 0.2 gpt	1	
56.30	8,592	40.3	2.00	1,789.0	17,340	2.0	83.0	39	Start 2.00 ppg increase gel 0.2	1	5
67.00	8,257	40.3	2.00	2,198.0	49,410	2.0	86.0	46	Fluid check		
70.30	8,332	40.0	3.00	2,317.0	58,930	2.0	82.0	42	Start 3.00 ppg 11.5 pH	1	6
80.20	8,241	40.0	4.00	2,676.0	101,900	2.0	83.0	46	Start 4.00 ppg 12 pH	1	7
89.20	7,968	38.6	0.20	2,992.0	147,700	0	76.0	9	Flush	1	8
	7,623	37.0	0.00	3,208.0	147,700	0			Shut down	1	9
97.00	4,995	0.0	0.00	3,208.0	147,700				ISIP	1	i
102.00	4,435								5 min	1	x
107.00	4,311								10 min	1	y
112.00	4,266								15 min	1	z

Main Treatment Results:

Bottom Hole ISIP (psi)	Bottom Hole ISIP (psi/ft)	PID* (psi)	Max prop conc (ppg)	Well Stage
9,601	0.91		4.00	1

*PID: Proppant induced friction

Final Inventory:

Clean Volume Design (bbl)	Clean Volume Metered (bbl)	Prop Volume Design (Mlb)	Prop Volume Blender Actual (Mlb)	Prop Volume Inline Actual (Mlb)	Acid Design (gal)	Acid Actual (gal)	Treating Pressure Average (psi)	Treating Pressure Maximum (psi)	Injection Rate Average (bpm)	Injection Rate Maximum (bpm)	Well Stg
3,051	3,209	157.50	157.50	147.70	0	0	8,321	8,904	38.3	40.8	1

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General Information

IPT specialist: **David Morris**

Company:	Peak Energy Resources, LLC	Date:	October 6, 2009
Well name:	Voigt #32-34	Stage no:	1
County:	Dunn	State:	ND
Field:	Wildcat	Formation:	Bakken

Design done by: IPT
Company engineer / Contact number: Vic Rudolph / 970-769-1677
Company field rep / Contact number: Rick Sandel / 701-759-3098
Service company / District: SLB / Willston / 701-572-8393
Service company personnel: Nick Fynan / Mark / Charles / Alejandra / Tom
Base treatment fluid type: 40 # Borate

Wellbore Configuration:

Pipe		Weight	Grade	From	To	Burst Rating					
Type	Size (in)	(lb/ft)	(type)	(ft)	(ft)	100%	80%				
Casing	7.000	29.00	P-110	0	5,891	11,220	8,976				
Casing	7.000	32.00	P-110	5,891	10,906	12,460	9,968				
Liner	4.500	13.50	P-110	0	9,959	12,410	9,928				
Liner	4.500	11.60	P-110	9,959	15,035	10,690	8,552				

Packer depth (ft):
PBTD (ft):
Surface maximum pressure limit (psi):
Burst limit equipment type: Popoff/lines/wellhead
Downhole surface burst limit (psi): 8,500
Downhole limit location: Liner
Maximum pressure (psi): 10,000
Authorized by: Vic Rudolph
Backside pressure (psi): 4,000

Perforated or Port Intervals:

Top MD	BTM MD	Top TVD	EHD	Holes	Total	SPF/	Capacity		Flush		
(ft)	(ft)	(ft)	(in)	(no.)	Holes	Phasing	(bbl)	(gal)	O(+)/U(-)	(bbl)	(gal)
14,455.0	14,463.0	10,533.1	0.42	48	48	6/60	218.5	9,177		218.5	9,177

Job Slurry Inventory:

			Materials on Location						
Slurry Description		Design	Pre-Treatment			Post-Treatment Used			
Component	Type	Amount	Required	Strap	Excess	Metered	Actual	(%)	Unit
Fluid	Fresh water	117.8	117.8	1,050.0	932.2	134.7	134.4	100	Mgal
		2,805	2,805	25,000	22,195	3,208	3,200	100	bbl
Tanks	On location	6	6	100	94				#
Crosslinked gel	YF140LGD	109,000				113,190		104	gal
Linear gel	40# Linear	10,000				14,154		142	gal
Slick water	Slick water	8,800				9,072		103	gal
Carbon dioxide									ton
Nitrogen									Mscf
Acid									gal
Proppant 1	18/40 VersaProp	156,500	156,500	1,068,500	912,000	147,700	157,450	94	lb
Proppant 2									lb
Proppant 3									lb
Proppant 4									lb

Job Chemical Inventory:

						Materials on Location					
Chemical			Loading			Pre-Treatment		Post-Treatment			
#	Type	Name	Unit	Design	Actual	Required	Strap	Metered	Actual	%	Unit
1	Gel concentrate	B-306	gpt	10	10	1,090	5,420	1,095	1,217	90	gal
2	Gel Stabilizer	J353	gpt	0	1-0	60	660	69	42	164	gal
3	Clay Swelling	L064	gpt	1	1	118	990	129	134	96	gal
4	Scale Inhibitor	Gyptran T106	gpt	1.4	1.4	165		0			gal
5	Surfactant	F103	gpt	1	1	118	895	131	130	101	gal
6	Crosslinker	J920	gpt	6	6	654	5,598	686	624	110	gal
7	Breaker	J481	ppt	2	0.5-1	68	600	77			lb
8	Breaker	J475	ppt	1	0-1	27	110	28	27	104	lb
9	Breaker	J218	ppt	2	0-2	28	220	0	33	0	lb
10	Delayer	J511	gpt	4	2	436	2,505	210	200	105	gal
11	Friction Reducer	J600	gpt	1	1	9	180	0	0		gal
12	Bacteriacide	Biocide	gpt	0.4	0.4	44					gal

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Fluid, Gas and Proppant Inventory

Tank Inventory:

	Straps			
Tank (No.)	Initial (bbl)	Prime-up (bbl)	End (bbl)	Used (bbl)
1	500	500	100	400
2	500	500	100	400
3	500	500	100	400
4	500	500	100	400
5	500	500	100	400
6	500	500	100	400
7	500	500	100	400
8	500	500	100	400
9	500	500	500	0
10	500	500	500	0
11	500	500	500	0
12	500	500	500	0
13	500	500	500	0
14	500	500	500	0
15	500	500	500	0
16	500	500	500	0
17	500	500	500	0
18	500	500	500	0
19	500	500	500	0
20	500	500	500	0
21	500	500	500	0
22	500	500	500	0
23	500	500	500	0
24	500	500	500	0
25	500	500	500	0
26	500	500	500	0
27	500	500	500	0
28	500	500	500	0
29	500	500	500	0
30	500	500	500	0
31	500	500	500	0
32	500	500	500	0
33	500	500	500	0
34	500	500	500	0
35	500	500	500	0
36	500	500	500	0
37	500	500	500	0
38	500	500	500	0
39	500	500	500	0
40	500	500	500	0
41	500	500	500	0
42	500	500	500	0
43	500	500	500	0
44	500	500	500	0
45	500	500	500	0
46	500	500	500	0
47	500	500	500	0
48	500	500	500	0
49	500	500	500	0
50	500	500	500	0
Totals:	25,000	25,000	21,800	3,200

On-Site Inventory Totals:

Fluid Inventory:

Initial amount (bbl):	25,000
Fluid needed (bbl):	2,805
No. of tanks:	100
Existing bottoms (bbl/tank):	222
Possible bottoms (bbl):	50
Usable (bbl):	20,000
Usable (gal):	840,000
Excess usable (bbl):	17,195
Excess usable (gal):	722,200

Proppant Inventory:

18/40 VersaProp (lb):	1,068,500
Job total (lb):	1,068,500

CO_2 Inventory:

CO_2 Total (ton):	0

N_2 Inventory:

N_2 Total (Mscf):	0

Acid Inventory:

Acid Total (gal):	0

Comments:

This is half of all tanks on location

Proppant Inventory From Weight Tickets:

Proppant Type 1		Proppant Type 2		Proppant Type 3		Proppant Type 4	
Description	Weight (lb)	Description	Weight (lb)	Description	Weight (lb)	Description	Weight (lb)
18/40 VersaProp	2,440						
	46,960						
	49,040						
	48,020						
	39,340						
	47,200						
	7,540						
	47,040						
	3,000						
	41,760						
	45,280						
	48,760						
	45,100						
	46,340						
	36,700						
	9,340						
	4,000						
	43,900						
	45,820						
	46,300						
	45,760						
	49,620						
	27,520						
	43,520						
	17,800						
	42,960						
	47,940						
	44,280						
	45,220						
Proppant Totals:	1,068,500		0		0		0
Proppant Used:	157,450						
Proppant Remaining:	911,050		0		0		0
Source:	Weight Tickets		Weight Tickets		Weight Tickets		Weight Tickets

Remarks: Remarks: Remarks: Remarks:

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Proppant Storage:

Unit no.: 25789 Total (lb): 360,000

	(not used)				(not used)
Compartment no.:	1	2	3	4	5
Amount (lb):	120,000	120,000	70,000	50,000	
Mesh size:	18/40	18/40	18/40	18/40	
Name (type):	VersaProp	VersaProp	VersaProp	VersaProp	

Unit no.: 17313 Total (lb): 360,000

	(not used)	(not used)	(not used)	(not used)	(not used)
Compartment no.:	1	2	3	4	5
Amount (lb):	120,000	120,000	70,000	50,000	
Mesh size:	18/40	18/40	18/40	18/40	
Name (type):	VersaProp	VersaProp	VersaProp	VersaProp	

Unit no.: 9929 Total (lb): 360,000

	(not used)	(not used)	(not used)	(not used)	(not used)
Compartment no.:	1	2	3	4	5
Amount (lb):	120,000	120,000	70,000	50,000	
Mesh size:	18/40	18/40	18/40	18/40	
Name (type):	VersaProp	VersaProp	VersaProp	VersaProp	

Order to Empty:		Volume	
		Bin	Cum
Unit No.	Bin	(lb)	(lb)
25789	4	50,000	50,000
25789	3	70,000	120,000
25789	2	120,000	240,000

Comments:
All storage bins are from visual observation

Proppant Sieve Analysis:

Proppant type:	Versaprop				
Mesh size:	18/40				
12					
16	0.1				
20	32.2				
25					
30	58				
35	5.5				
40	3				
50	1.1				
Pan	0.1				
In spec (%):					

CO_2 Inventory:

	Straps		
Transprt	Initial	End	Used
(No.)	(ton)	(ton)	(ton)
1			
2			
3			
4			
5			
6			
7			
8			
9			
10			
Total:	0	0	0
Cool down:			
Total downhole:			0

Comments:

N_2 Inventory:

	Straps		
Transprt	Initial	End	Used
(No.)	(Mscf)	(Mscf)	(Mscf)
1			
2			
3			
4			
5			
6			
7			
8			
9			
10			
Total:	0	0	0
Cool down:			
Total downhole:			0

Comments:

Acid Inventory:

Tank/			Incl Diag
Transprt	Initial	End	Used
(No.)	(gal)	(gal)	(gal)
1 Diag			
1 RT			
2			
3			
4			
5			
6			
7			
8			
9			
Total:	0	0	0

Comments:

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Liquid Additive System Verification

Truck	Chemical	Liquid Add	Meter		Pump		Addition
Type	(Name)	(ID #)	(Type)	(PPUs)	(Type)	(Range)	Site
PCM	B-306	5	MicroMotion	6,000	Waukesaw	1.0-54	PCM
POD	J920	1	MicroMotion	6,000	Waukesaw	1.0-54	Suction Pod
PCM	J511	2	MicroMotion	6,000	Waukesaw	0.25-15	PCM Discharge
PCM	J353	4	MicroMotion	6,000	Waukesaw	0.25-15	PCM Discharge
PCM	L064	1	MicroMotion	6,000	Waukesaw	0.25-15	PCM Discharge
PCM	F103	3	MicroMotion	6,000	Waukesaw	0.25-15	PCM Discharge
	Biocide						3rd party in tanks
	Gyptran T106						3rd party in tanks
POD	J600	2	MicroMotion	6,000	Waukesaw	0.75-11	if needed
POD	J481						Dry Add
POD	J475						Dry Add
POD	J218						By Hand

Truck	Chemical	Metering Method		Implementation Method		Remarks
Type	(Name)	Meter	Pump	Automation	Manual	
PCM	B-306	X		X		
POD	J920	X		X		
PCM	J511	X		X		
PCM	J353	X		X		
PCM	L064	X		X		
PCM	F103	X		X		
	Biocide					
	Gyptran T106					
POD	J600	X		X		
POD	J481		X	X		
POD	J475		X	X		
POD	J218				X	By hand

		Liquid Additive Test Conditions						
		Blender	Chemical		Test Conditions			
Truck	Chemical	Clean Rate	Loading	Rate	Volume	Target	Actual	(%)
Type	(Name)	(bpm)	(gpt)	(gpm)	(gal)**	(mm:ss)	(mm:ss)*	Off
PCM	B-306	36.0	10.00	15.12		00:00		
POD	J920	36.0	6.00	9.07	1.00	00:07	00:07	0.0
PCM	J511	36.0	1.00	1.51	1.00	00:40	00:39	-2.5
PCM	J353	36.0	1.00	1.51	1.00	00:40	00:40	0.0
PCM	L064	36.0	1.00	1.51	1.00	00:40	00:40	0.0
PCM	F103	36.0	1.00	1.51	1.00	00:40	00:40	0.0
	Biocide			0.00		00:00		
	Gyptran T106			0.00		00:00		
POD	J600	36.0	1.00	1.51	1.00	00:40	00:39	-2.5

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POD	J481			0.00		00:00		
POD	J475			0.00		00:00		
POD	J218			0.00		00:00		

*Must type in as h:mm:ss. **1 liter = 0.264 gallon.

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On-Site Gel Hydration Method

	Work Tanks	Hydration Unit	Remarks
On-site hydration method (X):		X	
Number (work tanks/hydration units):		1	
Hydration volume (bbl):		250	
Highest clean rate (bpm):		40	
On-site hydration time (min):		6.3	
On-site shear method confirmed[1] (Y/N):			
1. Shear is an important issue mixing gel to achieve desired hydration character.			
Does a backup gel pump exist (Y/N):		Y	
Does a backup gel flow meter exist (Y/N):		N	
Do work tanks have a roll line (Y/N):			

Gel Hydration Test Verification:

Lab/Target Testing	Base	Hydration Buffer			Gel	Hydration Test			
Description	pH	(type)	(gpt)	pH	(gpt)	(°F)	(min)	(cp)	
Lab Test	7.50				10.0	71		46	

Field average tank water temperature (°F): 88.0
Temperature adjusted lab viscosity (cp):
On-site hydration time (min): 6.3

Field Testing	Base	Hydration Buffer			Gel	Hydration Test			
Test Description	pH	(type)	(gpt)	pH	(gpt)	(°F)	(min)	(cp)	
Test 1	7.0				10.0	80	6.0	52	
Test 2	6.5				10.0	76	6.0	51	

Comments:
Chart will not go past 40 cp

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Fluid Chemistry Verification:

All tests below include the following base chemical formulation:
1.0 gpt F103, 1.0 gpt L-64, 1.4 gpt T106 & 0.4 gpt bio

	Chemical	Testing Description						
	Name	Lab	Field	2	3	4	5	6
Gel loading (gpt):	B-306	10	10	10	10	10	10	10
Temperature (°F):		71	80	80	80	76	76	65
Viscosity (cp):		46	51	51	51	51	51	64
Base gel (pH):		7.5	7.0	7.0	7.0	6.5	6.5	6.5
Buffer (gpt):	J511	1-4	0	2	1	3	4	3
Buffer (gpt):	Name							
Chemical/Buffered (pH):		7.5	7.5	7.5	6.5	6.5	6.5	7
Crosslinker (gpt):	J920	6	6	6	6	6	6	6
Crosslinker (gpt):								
Crosslinked (pH):		12	11.5	12	12	12	12	11.5
Vortex closure (min):		1-3	0:06.8					
Crown time (min):		0:05	0:07	0:10	0:09	0:15	0:18	0:11
Lip time at CKC = 6 (min):				0:52	0:46	1:30	2:10	1:50
Pipe time (min):			5.7	5.7	5.7	5.7	5.7	5.5
CKC at pipe time (0 - 10):			8	8 - 9	8 - 9	8 - 9	9	9
Recommended formulation								

Comments:
3 other test were done on 10/6, it was found that the J920 had cooled down so it was off loaded from the Pod back to the transport which test shows this.

Service Company Water Analysis:

Temperature (°F):	80	Bicarbonates:	550
Specific gravity:	1.000	Sulfates:	
pH:	7.00	Calcium:	
Iron:	<6	Magnesium:	
Chlorides:	<500	Boron:	

Comments:

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Breaker Schedule:

Bottom Hole				Job Type				Chemical Schedule				
No Prop Volume (Gal)	Slurry Rate (bpm)	Prop Conc (ppg)	Stage Time (min)	Fluid Fluid Type	B	Cum Time (min)	Time in Fracture (min)	J353	J481	J475	J218	Name
25,000	40	0.00	15	35#B0RATE		15	69	1	0.5	0	0	
2,000	40	0.75	1	35#B0RATE		16	54	1	0.5	0	0	
15,000	40	0.00	9	35#B0RATE		25	52	1	0.5	0	0	
18,000	40	1.00	11	35#B0RATE		36	44	1	0.5	0	0	
22,000	40	2.00	14	35#B0RATE		50	32	0	0.5	0	0	
15,000	40	3.00	10	35#B0RATE		60	18	0	1	1	0	
12,000	40	4.00	8	35#B0RATE		69	8	0	1	1	1	
8,800	40	0.00	5	IPT SLICKWATER		74	0	0	0	0	2	

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On-Site Equipment Inventory

Equipment on Location:

Treatment van(s):	1	Backside pump:	1
Blender(s):	1	Wellhead isolation:	1
Chemical add unit(s):	0	Main line popoff:	1
Chemical float(s):	1	Backside popoff:	1
Hydration unit(s):	1	Hydraulic power pack:	1
Gel transport(s)	1	Acid transport:	0
Proppant storage:	3	Conveyor belt(s):	0
Manifold:	1	J920 Transports	2

Comments:

Backup hydrauulic is a truck parked by sand chiefs.

Back side popoff is set to 5,000 per Peak

	Pump types:	HHP	Rate	Remarks
3	SupperPumpers	2,000		6,000
5	Condors	1,800		9,000
Totals:				15,000

High Pressure Configuration:

No. of lines to wellhead:	2
Diameter of risers (in):	4"
Maximum rate from service company (bpm):	64
Iron pressure rating from service company (psi):	10K
Wellhead isolation tool rating from service provider (psi):	10K

Low Pressure Configuration:

Unit type	Suction hoses		Discharge hoses		Remarks
	(No)	Size (in)	(No)	Size (in)	
Blender 1	2	8-4	6	4.00	1 - 8" & 1 - 4" suction
Blender 2					N/A
Hydration Unit	2	8-4	2	8-4	1 - 8" & 4 - 4"
Work tanks					

Water Transfer Configuration:

Primary water location:	Tanks	No. of location water tanks:	50
No. of off-site transfer lines:	0	No. of location work tanks:	0
Size of off-site transfer lines:	0	No. of transfer pumps on tanks:	1
No. of off-site transfer pumps:	0	No. of location transfer lines:	
Off-site transfer pump rate:	0	Size of location transfer lines:	4
Does off-site line backup exist:	0	Does location line backup exist:	0
Does off-site pump backup exist:	0	Does location pump backup exist:	0

Operational Notes:

10/4/09

Count tanks and all equipment on this side of location.

Bucket tested PCM #19558 LA pump#4 needs ET to fix, will not slow down.

LA 1, 2, & 3 Tested good.

Tested PCM LA 4 DCU was lose.

Water transfer are not hooked to all tanks, 1 pump not even hooked up.

Tanks are laid out 50 / 50 per side but can move water from side to side.

10/5/09

Found out while the Zane well was being treated that the PCM add 4 DCU went out and there were no spare DCU to replace the one that was out. The pump could be ran in manual mode or switch to the Pod LA 2.

10/6/09

PCM add 4 is working right now

J920 was cold ahd to push from the Pod back to transport and retest

Start J511 @ 3.0 gpt

Lower it to 1.0 gpt

Tank temp back up to +80 increase J511 to 2.0 gpt

Lost gel visc when gel tank ran empty from 51 to 39 cp

Gel visc back

Having pump problem on 4.0 ppg

Stage flush and shut pump down

Appendix A: IPT DFIT Analysis

September 28, 2009

Vic Rudolph
Peak Energy Resources, LLC
1910 Main Avenue
Durango, Colorado 81301

RE: Diagnostic Fracture Injection Test Analyses
Voigt 32-34H
Bakken Formation
Dunn County, North Dakota

Dear Mr. Rudolph:

Attached is the summary report for the analyses of the Diagnostic Fracture Injection Test performed on the Bakken from the perforations at 14,455 (10,533' MD) in the horizontal lateral completion of the Voigt 32-34H, Dunn County, North Dakota.

IPT appreciates the opportunity to work with you and Peak on this project. Please do not hesitate to call if you have any questions or require any additional assistance.

Sincerely,

Richard A. Burns
Vice President of Production and Reservoir Engineering

1.0 Executive summary

IPT analyzed and evaluated the diagnostic fracture injection test conducted on the Bakken completion in the Voigt 32-34H. This analysis was performed to obtain an accurate estimate of reservoir parameters and rock fracturing characteristics. The analysis of both the pre-closure and post-closure response suggests an average reservoir permeability of approximately 0.055 md. Reservoir pressure is calculated to be approximately 7,949 psia. The observed fracturing characteristics are similar to the original design recommendation parameters and no modifications are necessary to place the designed amount of proppant.

The injection test was conducted through a perforated interval at 14,455' - 463' MD (10,534' TVD) in the horizontal lateral of the Voigt 32-34H and was performed by pumping approximately 3,000 gallons of treated water at 10.0 bpm. Following the injection, the pressure fall-off was monitored for ~83 hours with surface digital pressure gauges. The pressure response was analyzed with pre-closure fracture evaluation techniques and post-closure pressure transient analysis (PTA) methods. The results from both analysis techniques are shown in Table 1.

The following are the general conclusions and observations of these evaluations:

- The pre-closure analyses demonstrated a fracture closure pressure gradient of 0.810 psi/ft, 8,546 psi. Utilizing these fracture closure pressure, the observed net pressure was matched with a leakoff coefficient of 0.0004 $ft/min^{1/2}$. This leakoff coefficient corresponds to an average reservoir permeability of 0.054 md across a net pay thickness of 43 feet.

- The post-closure PTA analysis suggests the Bakken interval has moderate permeability. Based upon the analysis of the late time pressure data trends, average reservoir permeability is estimated to be approximately 0.059 md and reservoir pressure is calculated to be 7,949 psi (0.753 psi/ft pressure gradient).

- The pressure decline response shows an equilibration character that can be caused by a number of different mechanisms. In most horizontal applications, it implies a near-well stress field associated with fracture reorientation and/or increased stress caused by the drilling process. The bottom-line is that it relates to a near-well width restriction that is caused by this stress field increase. The method for dealing with this is to have adequate fracture treatment viscosity upon fracture entry.

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Table 1: Reservoir parameters.

Reservoir Parameter	Injection Test Analyses	
	Pre-Closure Analysis	**Post-Closure Analysis**
Model	Fracture	Radial
Fracture propagation pressure (psi)	9,933	N/A
Propagation pressure gradient (psi/ft)	0.943	N/A
Fracture closure pressure (psi)	8,546	N/A
Closure pressure gradient (psi/ft)	0.810	N/A
Leakoff coefficient (ft/min$^{1/2}$)	0.0004	N/A
Effective reservoir permeability (md)	0.054	0.059
Flow capacity (md-ft)	2.160	2.537
Net pay thickness (ft)	43	43
Reservoir pressure (psig)	N/A	7,949
Reservoir pressure gradient (psi/ft)	N/A	0.753

2.0 Discussion of pre-closure analysis of injection test

IPT analyzed and evaluated the pre-closure portion of the pressure response from the fall-off test performed on the Bakken interval in the Voigt 32-34H. This analysis was performed to determine the fracture mechanics parameters for the Bakken formation.

Observations from the pre-closure evaluation are shown below:

- Hydraulic fracture propagation is confirmed by the typical diagnostic plots for an injection/falloff test: semi-log-of-time (Figure 1) and square-root-of-time (Figure 2) as discussed in SPE 29599. The semi-log-of-time plot confirms fracture closure. The square-root-of-time plot determines fracture closure pressure to be at approximately 796 minutes with a calculated bottom-hole closure pressure of 8,546 psi (0.810 psi/ft).

- The G-Function plot (Figure 3) suggests fracture closure pressure to be at approximately 8,546 psi (0.810 psi/ft). This diagnostic plot also demonstrates that a near-field stress/pressure equilibration exists. This diagnostic plot also demonstrates height recession which indicates fracture growth vertically into adjacent lower permeability intervals.

- The pressure decline response shows an equilibration character (approximately 800 psig) that can be caused by a number of different mechanisms. In most horizontal applications, it implies a near-well stress field associated with fracture reorientation and/or increased stress caused by the drilling process. The bottom-line is that it relates to a near-well width restriction that is caused by this stress field increase. The method for dealing with this is to have adequate fracture treatment viscosity upon fracture entry.

- The treatment pressure response and net pressure history match are shown in Figure 4. Utilizing the fracture closure pressure determined from the injection test, the observed net pressure character is matched with a leakoff coefficient of 0.0004 $ft/min^{1/2}$. This relates to a reservoir permeability of 0.054 md (utilizing a pay thickness of 43 feet).

- The fracture dimensions created during the subject injection test are shown in Figure 5.

The following are the graphical presentations used in the analysis:

Figure 1: Injection test pressure falloff analysis, semi-log-of-time plot.
Figure 2: Injection test pressure falloff analysis, square-root-of-time plot.
Figure 3: Injection test pressure falloff analysis, G-Function plot.
Figure 4: Injection test data and net pressure history match.
Figure 5: Profile of created fracture.

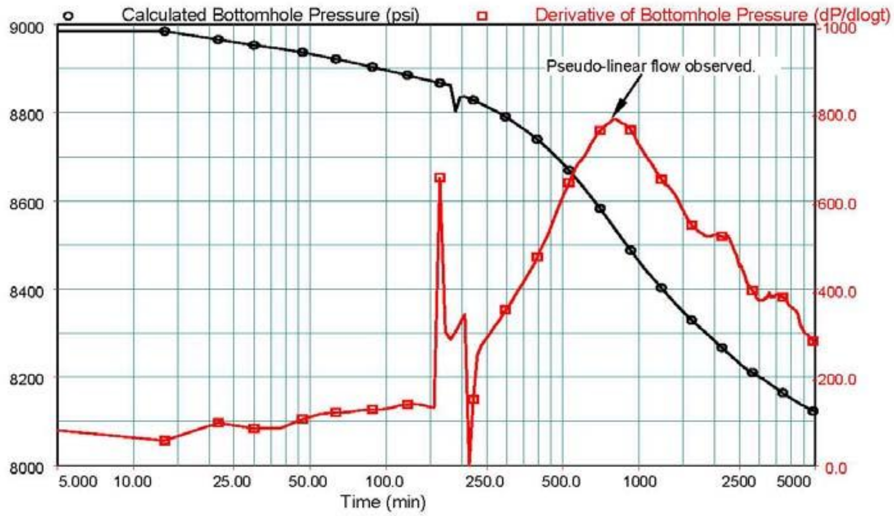


Figure 1: Injection test pressure falloff analysis, semi-log-of-time plot.

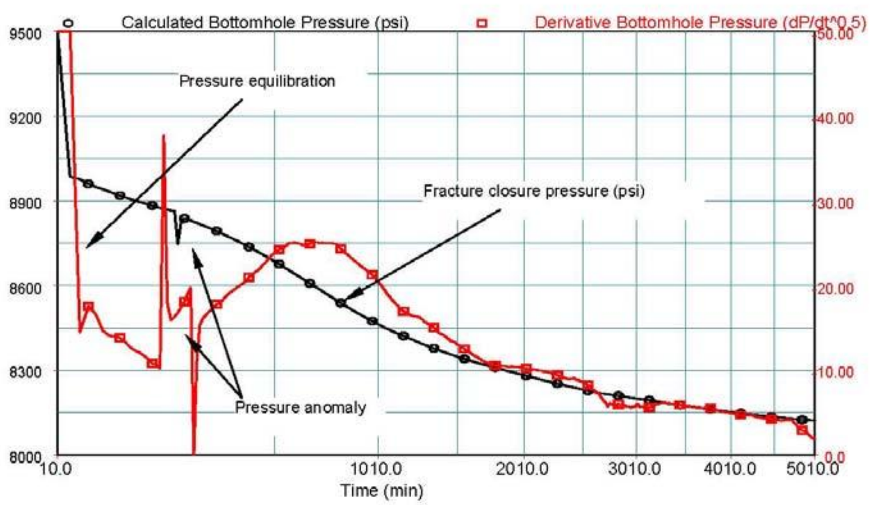


Figure 2: Injection test pressure falloff analysis, square-root-of-time plot.

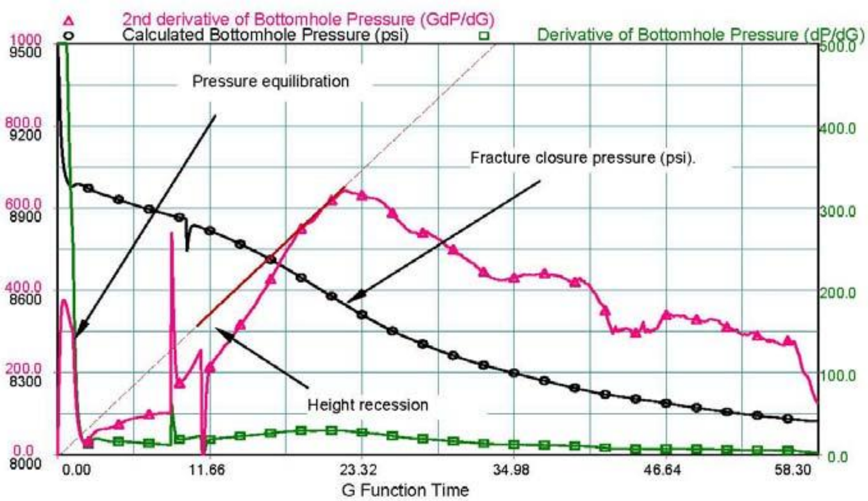


Figure 3: Injection test pressure falloff analysis, G-Function plot.

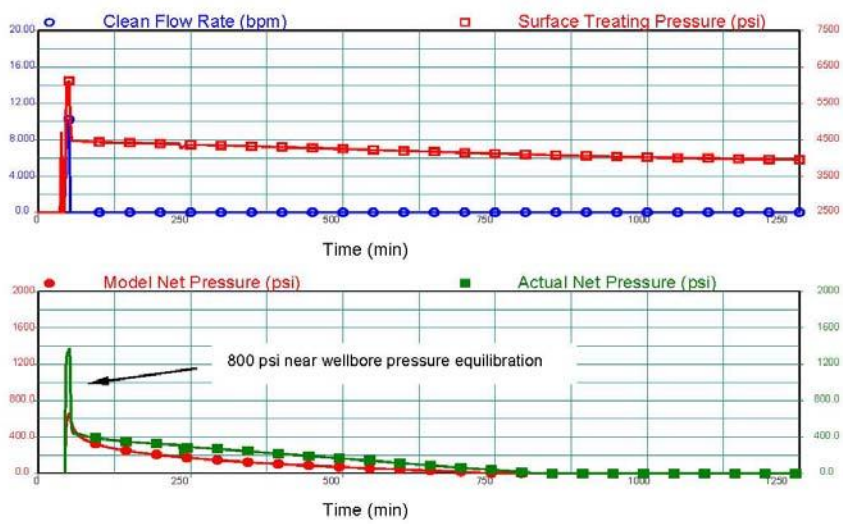


Figure 4: Injection test data and net pressure history match.

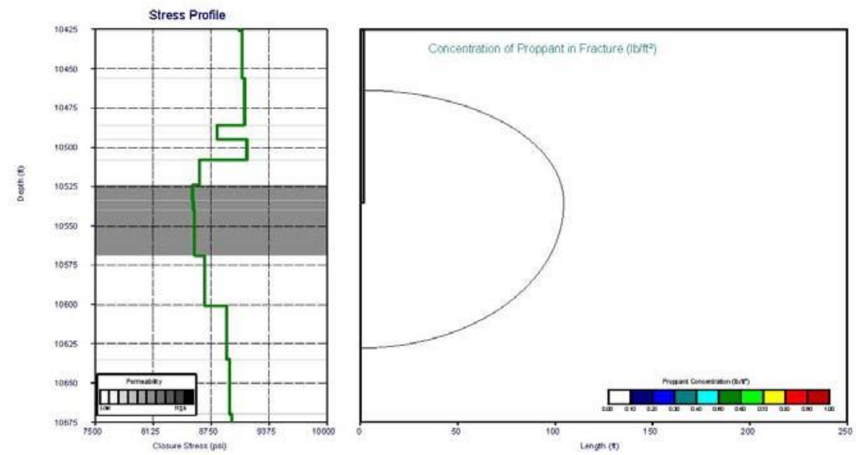


Figure 5: Profile of created fracture.

3.0 Review of post-closure analysis of injection test

The reservoir parameters calculated from the surface pressure fall-off analysis (PTA) of the injection/falloff test are shown in Table 1.

The following figures are used in the analysis:

Figure 6: Cartesian plot of surface and bottom-hole pressure.
Figure 7: Cartesian plot of surface and bottom-hole pressure: anomaly.
Figure 8: Diagnostic log-log plot.
Figure 9: Model match of pressure history.

Observations from the pressure fall-off (PTA) evaluation are shown below:

- The classical PTA log-log diagnostic plot (Figure 8) indicates several changes in flow regimes: 1.) Pre-fracture closure early time period demonstrates an open fracture response. 2.) A post-fracture closure transition period. 3.) Reach infinite acting radial flow.

- An anomaly in the pressure data occurs at approximately 3.88 hours (292 minutes into the pressure fall-off). This anomaly does not appear to impact the interpretation of the DFIT.

- The type curve match of the late-time pressure trends (Figure 8) suggests a reservoir flow capacity of 2.53 md-ft. Based upon 43 feet of net pay, average reservoir permeability is calculated to be 0.059 md.

- Based upon the late time pressure trends (Figures 8 and 9), current reservoir pressure is approximately 7,949 psia (0.753 psi/ft).

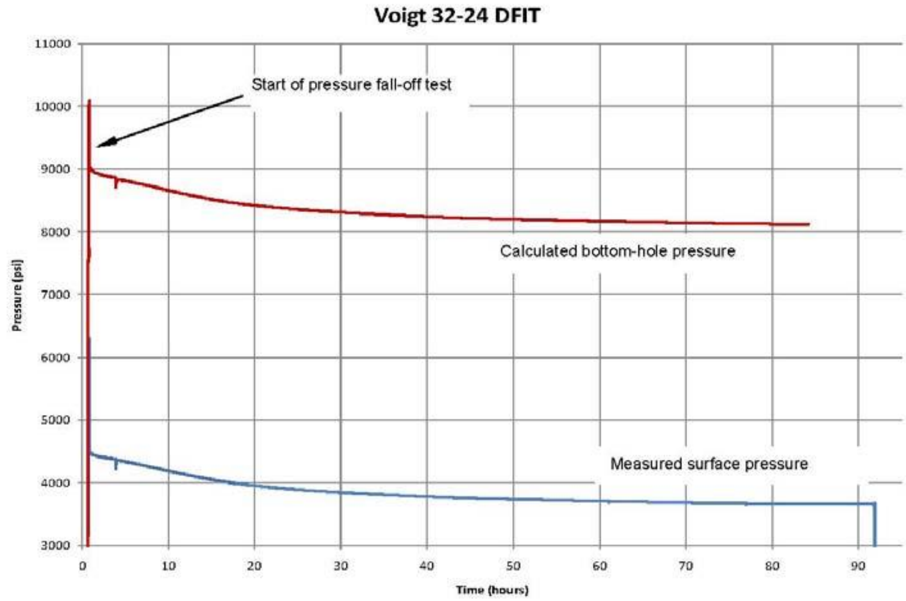


Figure 6: Cartesian plot of surface pressure and bottom-hole pressure.

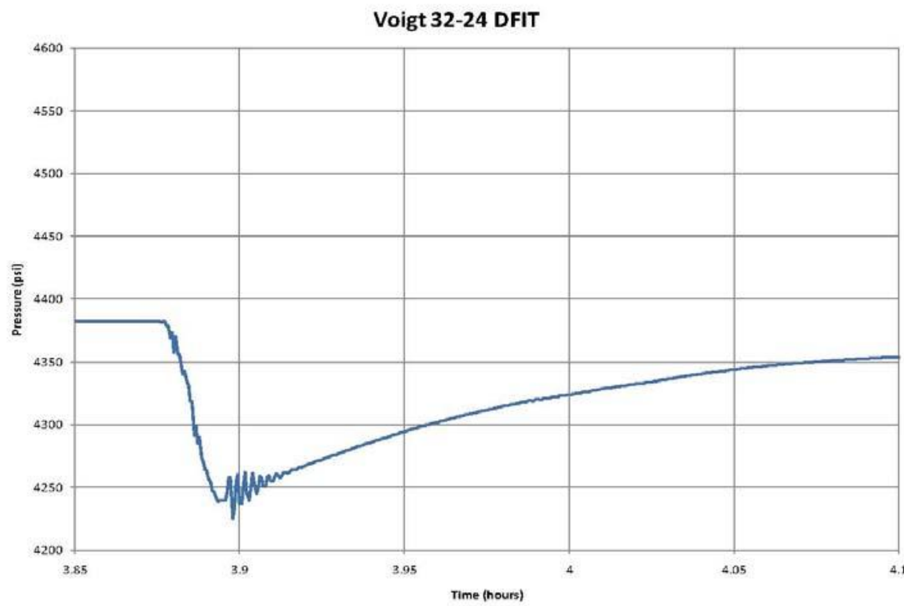


Figure 7: Cartesian plot of surface pressure and bottom-hole pressure: anomaly.

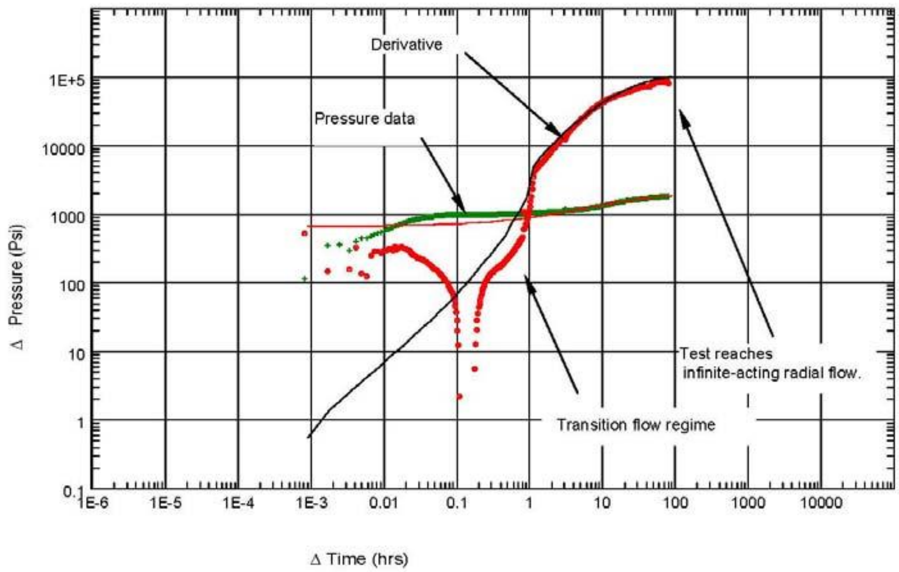


Figure 8: Diagnostic log-log plot.

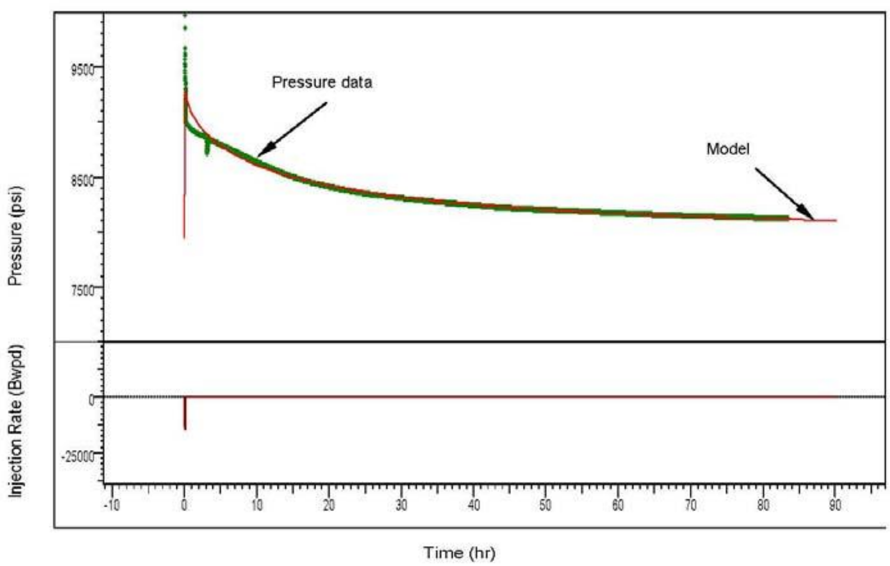
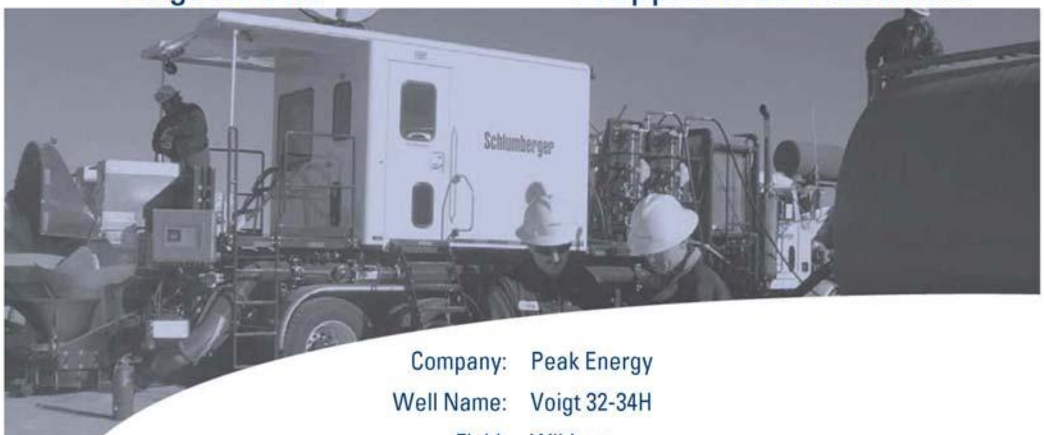


Figure 9: Model match of pressure history.

Appendix B: Service Company Proposal

405 Urban Street, Suite 401 • Lakewood, CO 80228, U.S.A. • Phone: (303) 216-0703 • Fax: (303) 216-2139
1050 East 2nd Street, #209 • Edmond, OK 73034, U.S.A. • Phone: (405) 842-2576 • Fax: (303) 216-2139

Voigt 32-34H — Propped Frac Treatment



Company:	Peak Energy
Well Name:	Voigt 32-34H
Field:	Wildcat
County:	Dunn
State:	ND
Date:	July 10th, 2009
Well Location:	S32 - T148N-R93W
Proposal Number:	1
Contact:	Vic Rudolph
Made By:	Natalia Simacheva
Service from District:	Williston, ND
District Phone:	701 572 8393

Schlumberger

EXECUTIVE SUMMARY

Enclosed are our recommendations for Schlumberger intervention on the referenced well. The proposal includes well data, design data, materials and resources requirements and cost estimates. The purpose of our services is to perform a Propped Frac Treatment.

Schlumberger has established a safety policy to which all Schlumberger personnel must adhere. A pre-job safety meeting will be held with customer representatives and other on location personnel to familiarize everyone with existing hazards and safety procedures. We would appreciate close cooperation between the customer representative and the Schlumberger representative to ensure a safe operation.

The estimated total cost of our services is **$ 730,077.10**. All costs are estimates only. Actual costs will be determined by time, material and equipment used during treatment. Taxes are not included. All work will be subject to Schlumberger then-current General Terms and Conditions or to the terms and conditions of a Master Service Agreement if one is in force between Schlumberger and Customer. This quote is valid for a period of thirty (30) days from the date submitted.

Thank you for considering Schlumberger.
Please do not hesitate to contact me with any questions or concerns.

Sincerely,

Natalia Simacheva
701 770 1097
NSimacheva@williston.oilfield.slb.com

WELL DATA

Well Data	
Pump Treatment Down:	Casing
Surface Temperature:	80 degF
Bottom Hole Static Temperature (BHST):	275 degF

Casing

OD	ID	Top Depth	Bottom Depth	Weight	Grade
4.500 in	4.000 in	0.0 ft	15035.0 ft	11.6 lb/ft	P110

PROCEDURES

1. MI (Move in) Schlumberger equipment.
2. Conduct Rig-up, Prime-up and pressure test safety meeting.
3. RU (Rig up) Schlumberger equipment and pressure test to customer master valve.
4. Conduct pre-job safety meeting.
5. Perform treatment per design pumping schedule and instructions of client representative.
6. Conduct post job rig down meeting.
7. Rig down Schlumberger equipment.
8. Conduct convoy meeting and move out Schlumberger equipment.

LOAD OUT SUMMARY

Job

Fluid/Material Type	Code	Quantity	% Excess	Load Quantity
Gelling Agent	B306	7707.0 gal	5.0	8092.3 gal
Clay Stabilizer	L064	824.6 gal	5.0	865.8 gal
Wetting Agent	F103	824.6 gal	5.0	865.8 gal
Stabilizer	J353L	420.0 gal	5.0	441.0 gal
Crosslinker	L010	4212 lb	5.0	4422 lb
Activator	M007	1373.4 gal	5.0	1442.1 gal
Delay Agent	J511	3586 lb	5.0	3765 lb
Breaker	J481	476 lb	5.0	500 lb
Breaker Encapsulated	J475	189 lb	5.0	198 lb
Breaker	J218	207 lb	5.0	218 lb
Versaprop	S129-2040	1095500 lb	1.2	1108646 lb

PUMPING SCHEDULE

Treatment 1					
Stage Name	**Pump Rate**	**Fluid Name**	**Stage Volume**	**Proppant**	**Prop. Conc**
	bbl/min		bbl		PPA
Pad	40.0	YF140LGD-J353(1), J481(0.5)	595		0.0
0.8 PPA	40.0	YF140LGD-J353(1), J481(0.5)	48	Versaprop	0.8
Pad	40.0	YF140LGD-J353(1), J481(0.5)	357		0.0
1.0 PPA	40.0	YF140LGD-J353(1), J481(0.5)	429	Versaprop	1.0
2.0 PPA	40.0	YF140LGD-J481(0.5)	524	Versaprop	2.0
3.0 PPA	40.0	YF140LGD-J481(1), J475(1)	357	Versaprop	3.0
4.0 PPA	40.0	YF140LGD-J481(1), J475(1), J218(1)	286	Versaprop	4.0
_Flush	40.0	WF105	210		0.0

Fluid Totals	
YF140LGD-J353(1), J481(0.5)	1429 bbl
YF140LGD-J481(0.5)	524 bbl
YF140LGD-J481(1), J475(1)	357 bbl
YF140LGD-J481(1), J475(1), J218(1)	286 bbl
WF105	210 bbl

Proppant Totals	
Versaprop	156500 lb

Treatment Execution						
Stage Name	**Stage Liquid Volume**	**Cum. Liquid Volume**	**Stage Prop. Mass**	**Cum. Prop. Mass**	**Stage Time**	**Cum. Time**
	bbl	bbl	lb	lb	min	min
Pad	595	595	0	0	14.9	14.9
0.8 PPA	48	643	1500	1500	1.2	16.1
Pad	357	1000	0	1500	8.9	25
1.0 PPA	429	1429	18000	19500	11.1	36.1
2.0 PPA	524	1953	44000	63500	14.1	50.2
3.0 PPA	357	2310	45000	108500	9.9	60.1
4.0 PPA	286	2596	48000	156500	8.2	68.3
_Flush	210	2806	0	156500	5.2	73.5

Treatment 2-7 – use the same design

MATERIALS SUMMARY

Job Total			
Fluid Description	**Additives**		**Quantity**
YF140LGD-J353(1), J481(0.5)	B306	10.0 gal/mgal	10003 bbl
	L064	1.0 gal/mgal	
	F103	1.0 gal/mgal	
	J353L	1.0 gal/mgal	
	J481	0.5 lb/mgal	
YF140LGD-J481(0.5)	B306	10.0 gal/mgal	3668 bbl
	L064	1.0 gal/mgal	
	F103	1.0 gal/mgal	
	J481	0.5 lb/mgal	
YF140LGD-J481(1), J475(1)	B306	10.0 gal/mgal	2499 bbl
	L064	1.0 gal/mgal	
	F103	1.0 gal/mgal	
	J481	1.0 lb/mgal	
	J475	1.0 lb/mgal	
YF140LGD-J481(1), J475(1), J218(1)	B306	10.0 gal/mgal	2002 bbl
	L064	1.0 gal/mgal	
	F103	1.0 gal/mgal	
	J481	1.0 lb/mgal	
	J475	1.0 lb/mgal	
	J218	1.0 lb/mgal	
WF105	B306	1.2 gal/mgal	1470 bbl
	L064	1.0 gal/mgal	
	F103	1.0 gal/mgal	
	J218	2.0 lb/mgal	

PRICE ESTIMATE

Equipment and Services

Code	Standard Description	Quantity	Unit List Price	Total List Price $	Discount Rate	Discounted Price $
28021003	Pump, Frac Rated > 1200 hhp Minimum	42 EA	5,000.00	210,000.00	76 %	50,400.00
28022003	Pump, Frac Rated > 1200 hhp Add Hr	0 HR	2,200.00	0.00	76 %	0.00
28022003	Pump, Frac Rated > 1200 hhp Add Hr	18 HR	2,200.00	39,600.00	76 %	9,504.00
28081000	Crosslinker Trailer	14 JOB	189.00	2,646.00	76 %	635.04
28082000	Chemical Float	14 JOB	268.00	3,752.00	76 %	900.48
28178003	Pump, Frac Rated Over 1200 hhp Standby	14 EA	2,900.00	40,600.00	76 %	9,744.00
28373000	Sand Chief First 2 Days	3 DAY	1,290.00	3,870.00	76 %	928.80
28380000	Sand Handle Equip, Add Days	15 DAY	244.00	3,660.00	76 %	878.40
28456000	Master Valve	7 DAY	61.50	430.50	76 %	103.32
28480010	Manifold, Frac 5001-10000 Psi	9 HR	330.00	2,970.00	76 %	712.80
28480200	Manifold, Suction	45 JOB	128.00	5,760.00	76 %	1,382.40
28500031	Blender, Pod 31-40 Bpm	7 EA	2,400.00	16,800.00	76 %	4,032.00
28505000	Blender, Pod 0-10 Bpm Add Hr	9 HR	360.00	3,240.00	76 %	777.60
28505031	Blender, Pod 31-40 Bpm Add Hr	0 HR	510.00	0.00	76 %	0.00
29100001	Transportation, Proppant ton-mile	54775 MI	1.23	67,373.25	76 %	16,169.58
29109001	Silo, Sand Set-Up Charge	3 JOB	322.00	966.00	76 %	231.84
29111002	Prop Pump Charge > 20/40 Other Prop	10955 CW	2.20	24,101.00	76 %	5,784.24
29112000	Slurry Concentration Service 0-4 ppa	483000 GA	0.06	28,980.00	76 %	6,955.20
58039000	On Location Time-All Other Units	112 HR	122.00	13,664.00	76 %	3,279.36
58576001	Truck Mounted Hoist	7 JOB	850.00	5,950.00	76 %	1,428.00
59200002	Transportation, Mileage Heavy Vehicles	3600 MI	5.52	19,872.00	76 %	4,769.28
59200005	Transportation, Mileage Light Vehicles	600 MI	3.24	1,944.00	76 %	466.56
59620000	Lab Work Including Tests and Evaluation	1 HR	101.00	101.00	76 %	24.24
59680000	Treatment Monitoring Service (TMS)	7 JOB	1,900.00	13,300.00	76 %	3,192.00
101532000	Pump, Backside Pressure	7 EA	640.00	4,480.00	76 %	1,075.20
102476000	Service Supervisor/Field Engineer	168 HR	105.00	17,640.00	76 %	4,233.60
102476001	Equipment Operator/Service Technician	1008 HR	85.00	85,680.00	76 %	20,563.20
102496031	PCM Process Unit 31-40 Bpm	7 EA	4,000.00	28,000.00	76 %	6,720.00
102497000	PCM Process Unit 0-10 Bpm Add Hr	9 HR	480.00	4,320.00	76 %	1,036.80
102497031	PCM Process Unit 31-40 Bpm Add Hr	0 HR	790.00	0.00	76 %	0.00
102946000	Fuel Surcharge (non-discounted)	0 EA	450.00	0.00	0 %	0.00
107264001	Regulatory Conformance Charge	18 EA	341.00	6,138.00	76 %	1,473.12
107265013	Communications Headset	18 EA	162.50	2,925.00	76 %	702.00
			Subtotals:	**$ 658,762.75**		**$ 158,103.06**

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Materials

Code	Standard Description	Quantity	Unit List Price	Total List Price $	Discount Rate	Discounted Price $
B306	PSG Polymer Slurry B306	7707 GA	33.00	254,331.00	72 %	71,212.68
F103	Surfactant, EZEFLO	825 GA	40.00	33,000.00	72 %	9,240.00
J218	Breaker	208 LB	4.40	915.20	72 %	256.26
J353L	Gel Stabilizer, HT	420 GA	13.70	5,754.00	72 %	1,611.12
J475	Breaker, EB-CLEAN	189 LB	29.00	5,481.00	72 %	1,534.68
J481	Breaker, WideFRAC 100 HTD	476 LB	11.80	5,616.80	72 %	1,572.70
J920	WideFRAC 100 LGD Conversion	763001 GA	0.19	144,970.19	72 %	40,591.65
L064	Clay Stabilizer	825 GA	31.20	25,740.00	72 %	7,207.20
S129-2040	S129-2040 Intermediate Specialty Prop	1095500 LB	0.89	974,995.00	55 %	438,747.75
			Subtotals:	**$ 1,450,803.19**		**$ 571,974.04**

Total Discount:	$	1,379,488.84
Job Price Estimate*:	**$**	**730,077.10**

* Please see Executive Summary for further information.

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Appendix C: Service Company Fluid Testing

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Fracturing Fluids QAQC Report
YF100LGD (40 lb/mgal)

Client:	Peak Energy
Well:	Voigt 32-34H/Zane 32-24H
County:	Dunn
Formation:	Bakken
BHST:	265 degF
MD:	15035/14954(ft)
TVD:	10515/10500(ft)
Perforation Start:	11185/11181(ft)
Perforation End:	14455/14780(ft)

Well Location: S32 – T148N – R93W
State: North Dakota
Country: United States

Service Order #:		**Lab Request #:**	**WND090196**
		Date Prepared:	**10-02-2009**

District:	WILLISTON
Phone:	1 701 572 8393
Fax:	1 701 572 8751

Lab Technician:	Scott Ross / Alisher Yunuskhojayev	Well Site Technician:	
Phone:	701 572 8393	Phone:	
Email Address:		Email Address:	

<u>Disclaimer Notice</u>

This information is presented in good faith, but no warranty is given by and Schlumberger assumes no liability for advice or recommendations made concerning results to be obtained from the use of any product or service.

Client : Peak Energy
Well : Voigt 32-34H/Zane 32-24H
Report # : WND090196
Date : 10-02-2009

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Section 1: District Lab Water Analysis

Water Analysis Results (1)														
Tank #	Tank ID	Sample #	Temp (degF)	pH ()	Sp Gravity ()	Iron (mg/l)	Chloride (%)	Chloride (mg/l)	Carbonate (mg/l)	BiCarbonate (mg/l)	Hydroxide (mg/l)	Magnesium (mg/l)	Calcium (mg/l)	TDS (mg/l)
1	1	1	73	7.00	1.00	0	0.10	500	0	708	0	162	267	1637
2	2	1	73	7.00	1.00	0	0.10	500	0	634	0	162	267	1564
3	3	1	74	7.00	1.00	0	0.10	500	0	708	0	0	401	1608
4	4	1	73	7.00	1.00	0	0.10	500	0	671	0	162	134	1467
5	5	1	76	7.00	1.00	0	0.10	500	0	647	0	81	134	1361
6	6	1	73	7.00	1.00	0	0.10	500	0	659	0	162	134	1455
7	7	1	73	7.00	1.00	0	0.10	500	0	610	0	81	267	1458
8	8	1	73	7.00	1.00	0	0.10	500	0	610	0	81	134	1325
9	9	1	73	7.00	1.00	1	0.10	500	0	671	0	162	134	1468

Client : Peak Energy
Well : Voigt 32-34H/Zane 32-24H
Report # : WND090196
Date : 10-02-2009

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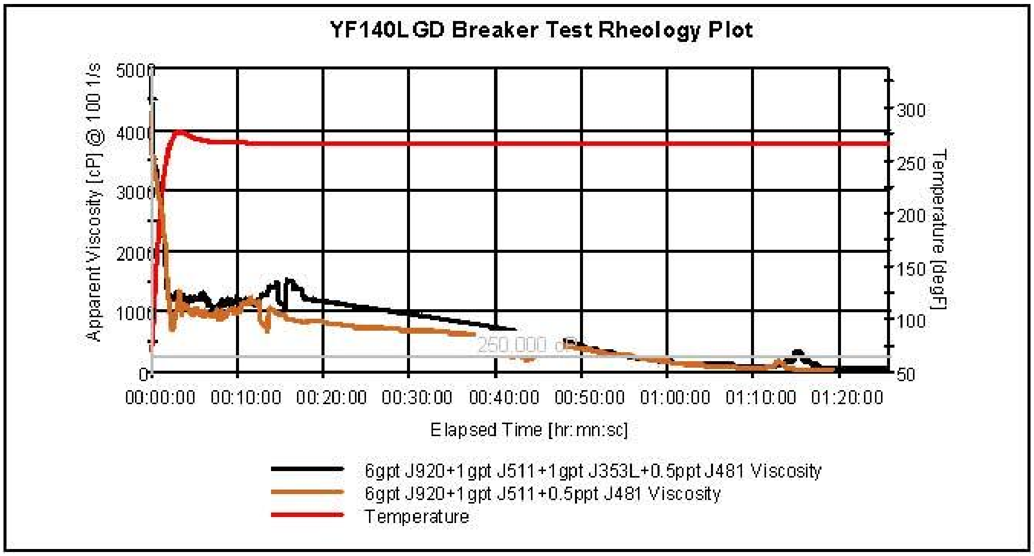
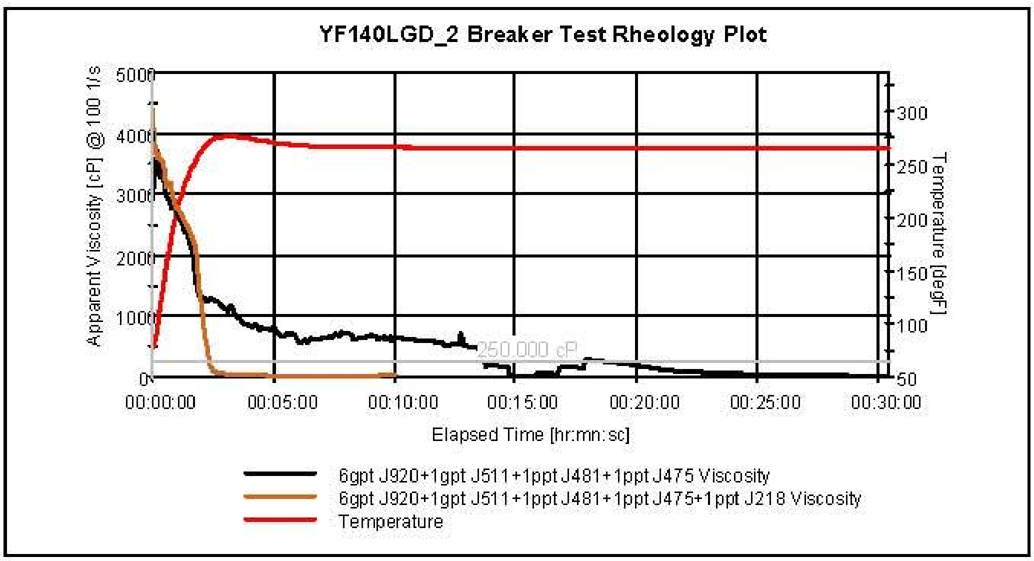
Section 2: District Lab Breaker Plots





3

YF140LGD	F103	1 gpt
B2-bob	L064	1 gpt
100 RPM	J481	2 ppt

Fluid YF140LGD	pH water	Time to full hydration	Temp.	Viscosity	pH base gel	pH gel+adds	Vortex closure	Crown	pH XL fluid	Fann 35 Reading						
										0 min	1 min	2 min	3 min	4 min	5 min	6 min
J920 (6gpt), No J511	7	3 min	71	46	7.5	7.5	1 sec	5 sec	12	300	300	300	300	300	300	300
J920 (4gpt), No J511	7	3 min	71	46	7.5	7.5	1 sec	5 sec	11	300	300	300	300	300	300	300
J920 (2gpt), No J511	7	3 min	71	46	7.5	7.5	1 sec	5 sec	10	300	300	300	300	300	300	300
J920 (6gpt), J511 (1gpt)	7	3 min	74	46	7.5	7.5	2 sec	5 sec	12	280	300	300	300	300	300	300
J920 (6gpt), J511 (2gpt)	7	3 min	74	46	7.5	7.5	3 sec	5 sec	12	200	250	280	300	300	300	300
J920 (6gpt), J511 (3gpt)	7	3 min	74	46	7.5	7.5	3 sec	5 sec	12	180	220	250	280	280	300	300
J920 (6gpt), J511 (4gpt)	7	3 min	74	46	7.5	7.5	3 sec	5 sec	12	20	30	35	40	45	70	140

STATUS OF ONGOING PROJECTS (IF ANY)

Peak has not been the recipient of any previous funding from the Commission.

AFFIDAVIT OF TAX LIABILITY

I, Alex McLean, certify that Peak North Dakota, LLC does not have any outstanding tax liability owed to the State of North Dakota or any of its political subdivisions.

Alex McLean 2/15/10

Alex McLean, PE President Date